MASTER'S THESIS

Indirect impacts of climate change to Finland: impacts to hydropower production in the Nordic electricity markets

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Earlier research has shown that it is important in climate change adaptation to take into account the indirect impacts of climate change. These are impacts resulting from climate change that have their initial direct effects outside Finland but reflect to Finland through for example international markets. For example, climate change could affect Finland indirectly through changing prices in global food markets. In this thesis I study the impacts of increasing hydropower potential in the Nordic electricity markets because of climate change. Nordic aspect is important as most of the hydropower in the Nordic power markets is produced outside Finland.

Climate science has shown that climate change can affect the precipitation and hydropower potential in the Nordic countries. Majority of studies give reason to believe that the hydropower potential will increase and change so that the potential increases more in winter and spring months. However, a lot of uncertainty is related to the results, which is crucial to bear in mind. According to a Nordic research report it is nevertheless very plausible that climate change will affect the hydrology and hydropower potential in Nordic countries from place to place.

Hydropower is an important technology in the Nordic electricity markets as depending on the year about half of the power is produced by it. As hydropower's producing costs are low the annual precipitation affects the electricity price levels so that in a wet year the prices decrease and vice versa. Hydropower has also its role in balancing the production and consumption of power as its production is comparably easy to adjust.

I use a simulation model of the Nordic electricity markets by Maria Kopsakangas-Savolainen and Rauli Svento in this thesis. In my analysis I increase the hydropower production (+10%) and study how it affects i.a. the price level and capacities of different power production technologies. This sensitivity analysis is made in various scenarios resulting from different climate and energy policies. In the thesis' simplified setting increasing the amount of hydropower decreased significantly the price of electricity and thus profits of electricity producers and decreased the amount of thermal power production. Thermal and nuclear production are important technologies for Finland and thus the results are interesting from the Finnish point of view. The results are in-line with a previous Norwegian study. Another potentially significant impact of climate change might the decreasing electricity consumption due to warmer winters but is out of the scope of this thesis.

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climate change, indirect impacts, adaptation, hydropower, Nordic electricity markets, environmental economics, energy economics

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Tiivistelmä□□ Referat – Abstract

Aikaisempi tutkimus antaa viitteitä siitä, että ilmastonmuutokseen sopeutumisessa on tärkeää ottaa huomioon myös ns. epäsuorat vaikutukset eli sellaiset vaikutukset, joiden suorat vaikutukset tapahtuvat jossain muualla, mutta jotka heijastuvat Suomeen esimerkiksi kansainvälisten markkinoiden välityksellä. Esimerkiksi ilmastonmuutos saattaa vaikuttaa epäsuorasti Suomeen ruoan maailmanmarkkinahintojen kautta. Tässä työssä tarkastelen tähän kehikkoon aseteltuna ilmastonmuutoksen vaikutuksia Pohjoismaisiin sähkömarkkinoihin sadannan ja siten vesivoimatuotantomäärien muutosten myötä. Tällöin epäsuorilla vaikutuksilla on potentiaalisesti suuri rooli, sillä suurin osa Pohjoismaisesta vesivoimatuotannosta toteutuu Suomen ulkopuolella.

Ilmastonmuutoksen tieteellinen tutkimus on osoittanut, että ilmastonmuutos voi vaikuttaa merkittävästikin sadantaan ja vesivoimatuotantoon Pohjoismaissa. Suuri osa tutkimuksista viittaa siihen, että vesivoimapotentiaali kasvaa ja muuttuu niin, että talvi- ja kevätkuukausina valuma kasvaa enemmän. Tuloksiin liittyy kuitenkin paljon epävarmuutta, minkä ymmärtäminen on tärkeää. Pohjoismaisen tutkimusraportin mukaan on kuitenkin erittäin todennäköistä, että ilmastonmuutos muuttaa hydrologiaa ja vesivoimapotentiaalia Pohjoismaissa eri alueilla eri tavoin.

Vesivoimalla on Pohjoismaisilla markkinoilla merkittävä asema, sillä vuodesta riippuen noin puolet sähköntuotannosta tuotetaan sillä. Koska vesivoiman tuotantokustannukset ovat alhaiset, vuotuinen sadanta heilauttelee sähkön hintaa niin, että sateisena vuotena sähkön hinta laskee ja päinvastoin. Vesivoimalla on myös roolinsa sähkön tuotannon ja kysynnän yhteensovittamisessa, sillä vesivoiman tehon säätö on käytännössä muita sähköntuotantomuotoja helpompaa.

Käytän tutkielmassa Maria Kopsakangas-Savolaisen ja Rauli Sventon sähkömarkkinoiden simulointimallia, missä syötän lisää vesivoimaa (+10 %) markkinoille ja tutkin miten se vaikuttaa mm. hintatasoon ja eri teknologioiden tuotantomääriin. Teen herkkyysanalyysia eri ilmasto- ja energiapolitiikan skenaarioissa. Yksinkertaistetussa asetelmassa vesivoimamäärän lisääminen laskee sähkön hintaa markkinoilla merkittävästi ja vähentää tuotantolaitosten voittoja sekä lämpövoimalaitosten kapasiteetteja. Polttolaitokset ja ydinvoima ovat Suomelle tällä hetkellä tärkeitä teknologioita ja tulokset ovat siksi Suomen kannalta kiinnostavia. Tulokset ovat yhdenmukaisia aikaisemman Norjalaisen raportin kanssa, jossa ilmastonmuutoksen myötä polttolaitokset Suomessa vähenivät ja sähkön tuonti Suomeen kasvoi. Tulosten mukaan ilmastonmuutos saattaa siis vaikuttaa epäsuorasti sähköntuotantoon Suomessa. Toinen oleellinen ilmastonmuutoksen vaikutus sähkömarkkinoihin on talvien lämpenemisen myötä vähenevä sähkön kysyntä, jonka tarkastelu jää tutkielmani ulkopuolelle.

Avainsanat – Nyckelord – Keywords
ilmastonmuutos, epäsuorat vaikutukset, ilmastonmuutokseen sopeutuminen, vesivoima, pohjoismaiset sähkömarkkinat, ympäristöekonomia

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Glossary of terms and abbreviations

Balancing power – power capacity needed to balance consumption and production of electricity

CES – Climate and Energy Systems, a research program funded by the Nordic Energy Research

CHP – Combined heat and power

ENTSO-E – European Network of Transmission System Operators for Electricity (see also TSO)

ETS – European Emissions' trading scheme

EUA – EU emission allowance traded in the ETS

GCM – Global Circulation Model, a type of climate model

IEA – International Energy Agency

IPCC – International Panel on Climate Change

Midmerit generator – thermal generator with lower variable costs but higher investment costs than peak generators

Nordic electricity markets – Electricity markets of Denmark, Finland, Norway and Sweden

Nord Pool – Electricity marketplace where most of the electricity used in Nordic electricity markets is traded

NREAP – National Renewable Energy Action Plans delivered to the EU by member countries to fulfil the renewable energy obligations

OECD – Organisation for Economic Co-operation and Development

Peak generator – thermal generator used as balance power, with high variable costs but low investment costs

RCM – Regional Circulation Model, a type of climate model

RTP – Real-Time Pricing in the electricity markets (electricity is billed by the hour)

TSO – Transmission System Operator, National enterprises that maintain the main electricity grids and interconnections

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1. Introduction

Climate change can affect energy production in a number of ways. Mitigation of climate change means new methods and sources of energy production to cut greenhouse gases. New production methods and efficiency goals create pressure also to change existing ways to distribute and use energy. On the other hand climate change can shape the environment where energy is produced and distributed. For example renewable power production is an essential part of the energy mix in the Nordic countries and can be affected by climate change. Thus mitigation and adaptation go hand in hand in the energy sector to limit the risks of climate change.

Although adaptation to climate change is often considered local, it also has international dimensions. For example Finland is not only affected by the changes that happen directly in Finland – as an open economy, Finland can experience changes for example in global prices of commodities (e.g. energy, food) that happen elsewhere because of climate change. The indirect impacts of climate change to the Finnish economy and society were studied in the FICC-project by CMCC in 2015 (Bosello, Orecchia & Standardi 2015). The study was carried out using a global general equilibrium (CGE) model which took into account results from global climate change impact studies on crops' productivity, tourism flows, sea-level rise, residential energy demand, river floods, health and fisheries. The results of the study suggest that "the intersectoral and international trade effects are likely to be very important, potentially, more than the direct effects triggered by climate change itself." (Bosello et. al. 2015, 27)

Stockholm Environment Institute has introduced a conceptual framework for assessing indirect impacts of climate change (Stockholm Environment Institute, 2014). In this framework indirect impacts are arranged in two baskets according to how easy they are to determine. Trans boundary impacts (such as impacts on a shared river) can be easier to assess while tele connected impacts, impacts that are transmitted through more complicated links, can be more difficult to assess. The basic concept of the framework is that a direct impact of climate change somewhere affects a "receptor system" (for example an international supply system) and is transmitted elsewhere through a pathway. Four main pathways are recognized and they are people (e.g. movement of people), bio-physical (e.g. a shared river), trade (e.g. prices of commodities) and finance (e.g. flow of capital).

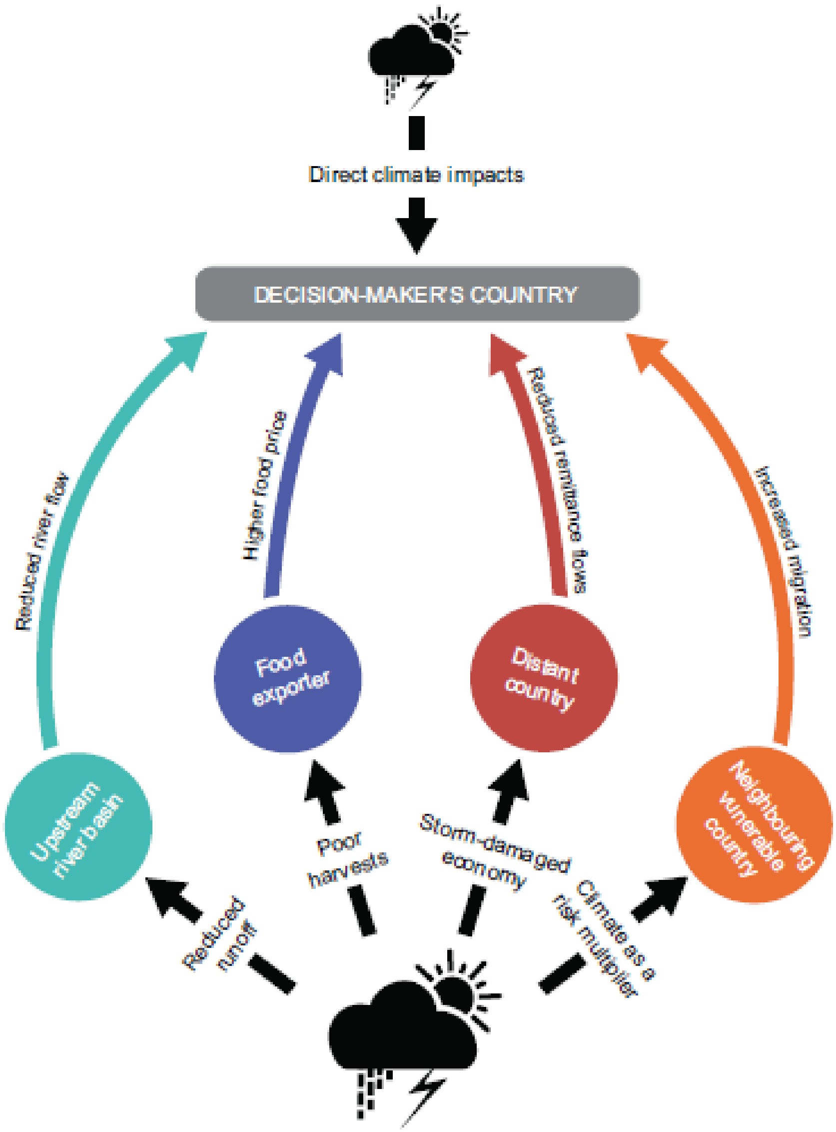


Figure 1 Direct impacts of climate change can affect countries elsewhere through different pathways. (Stockholm Environment Institute, 2014)

Put in SEI's framework, the focus of this thesis is in the increasing precipitation in Nordic countries (a direct impact of climate change) and its impacts on hydropower production (receptor system) which affects Finland through Nordic electricity markets (the trade pathway). Hydropower has a significant role in the Nordic power markets as depending on the year, approximately 50 % of the electricity is produced by hydropower. In a wet year more hydropower is produced and the price of electricity tends to decrease like in

2015 (e.g. HS, 2015, in Finnish). The international dimension of the phenomenon is important as most of the hydropower production in the Nordic electricity markets is located outside Finland. As hydropower is renewable, practically carbon neutral and a flexible part of the power system it is important also from the climate change mitigation perspective.

A Nordic electricity market model by Maria Kopsakangas-Savolainen and Rauli Svento was used in this thesis (Kopsakangas-Savolainen & Svento, 2012). A sensitivity analysis was made on a Nordic scale in different scenarios to study how the increase in hydropower production affects the price level, capacities of thermal producers and profits of nuclear and hydro producers' in a hypothetical setting in 2030-2035. The price of electricity is an interesting topic at the moment in Nordic electricity markets as among other things new wind power is driving it down and also capacity markets are discussed, although thanks to large hydropower reservoirs Nordic countries are in a privileged position to increase intermittent power production (Fortum, 2015, 16). There is a discussion also in Finland how the increasing need for balancing power (because of new intermittent production) is fulfilled (e.g. YLE, 2012, in Finnish). In this thesis I focus on the effects of increased hydropower production in an economic market model (no transmission constraints and only electricity) but there are several aspects (e.g. hydropower modelling, transmission constraints, intermittent power modelling, chp plants and heat markets) that are significant to the issue but beyond the scope of this thesis.

The thesis is structured as follows. In chapter two the context of the electricity markets and climate change is presented. The energy markets are going through a throughout change as countries are trying to meet their climate change mitigation goals. The Nordic electricity markets, climate mitigation policies and climate change impacts are briefly introduced. In chapter three the Nordic market model is introduced. Chapter four presents the data and the scenarios used. Chapter 5 presents the results, chapter 6 discussion and chapter 7 conclusions. All the results of the model runs are presented in the end after the references and data sources.

2. The context of climate change and electricity production and consumption

In this chapter the Nordic electricity markets (2.1) and climate change mitigation policies in them (2.2, pg. 16) are presented. After this Climate change impacts on electricity markets (2.3, pg. 24) and Climate change impacts on hydropower potential in the Nordic countries (2.4, pg. 28) are introduced.

2.1. Nordic electricity markets

Nord Pool is the international electricity market formed by four Nordic countries (Norway, Sweden, Finland and Denmark) and three Baltic countries (Estonia, Lithuania and Latvia) where most of the electricity consumed in the Nordic region is traded (NordPoolSpot, 2013, 6). It is owned by the Transmission System Operators (TSOs) that are responsible for the electricity grid and the security of supply in the countries. In Nord Pool Spot the system and area prices for the wholesale of electricity in the Nordic region are formed.

Deregulation of electricity markets and the start for a common Nordic market began from Norway where power markets were deregulated in 1990. Other Nordic countries followed the example one by one and the Nordic power markets were united in 2000. Power is traded in the day-ahead markets (Elspot) where most of the trade takes place and in the intraday markets (Elbas) which were formed to contribute to the security of supply. In addition to Elspot and Elbas financial contracts of up to 6 years are made in the financial markets. (NordPoolSpot, 2016)

Nordic power production was 389,513 TWh in 2014. Of this 214 TWh was produced by hydropower, 85 TWh by nuclear power, 52 TWh by renewables and 38 TWh by fossil fuels. Most of the hydropower is generated in Norway and Sweden whereas most of the thermal power production takes place in Denmark, Finland and Sweden. Nuclear power plants are located in Sweden and Finland and most of the wind power is generated in Sweden and Denmark. (Table 1, Figure 2 & Figure 3)

Table 1 Generation capacities in the Nordic Region in 2013. (Table source: NordReg, 2014)

	Denmark	Finland	Norway	Sweden	Nordic Region
Installed capacity (total)	14,861	17,300	32,879	38,273	103 313
Nuclear power	-	2,752	-	9,531	12 283
Other thermal power	6,989	11,135	1,040	8,079	27 243
-Condensing power	-	2,465	-	1,375	3 840
-CHP, district heating	1,929	4,375	-	3,631	9 935
-CHP, industry	562	3,180	-	1,498	5 240
-Gas turbines etc.	-	1,115	-	1,575	2690
Hydro power	9	3,125	30,900	16,150	50 184
Wind power	4,809	288	811	3,745	9 653
Sun power	563	0	N/A	43	606

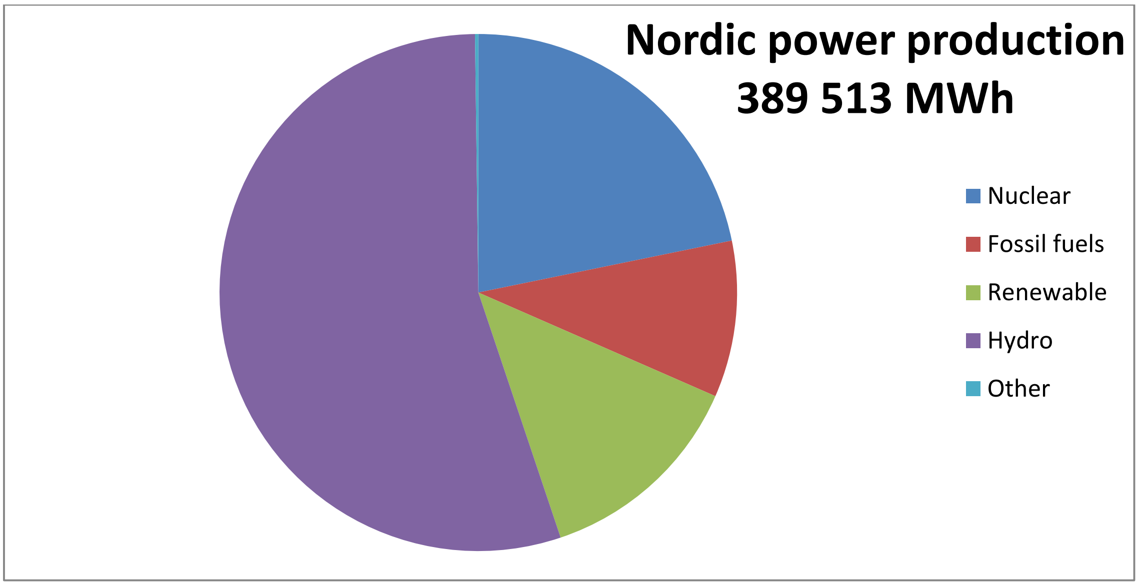
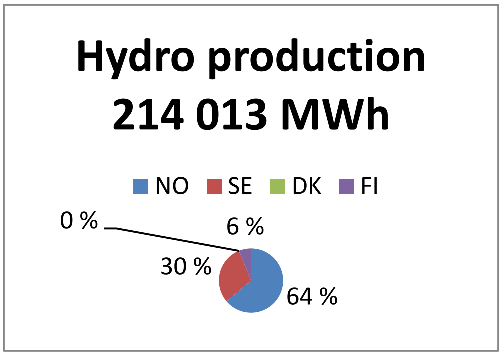
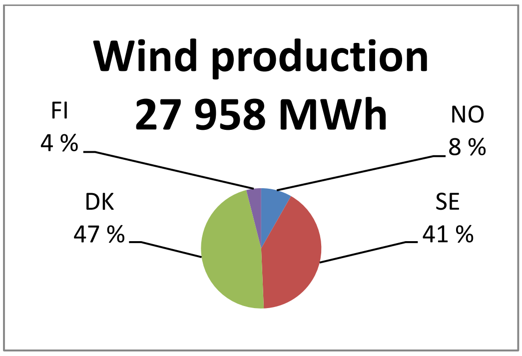
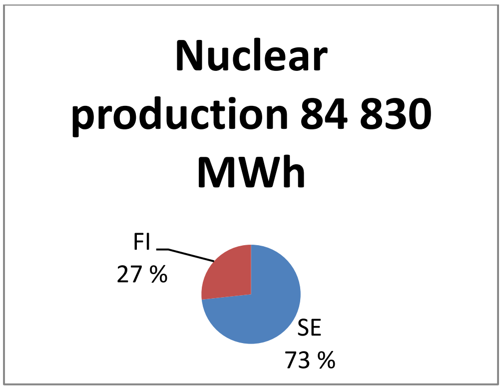
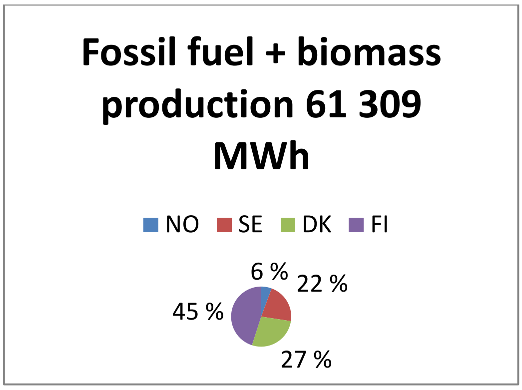


Figure 2 Nordic power production by sector in 2014. (Data: ENTSO-E)









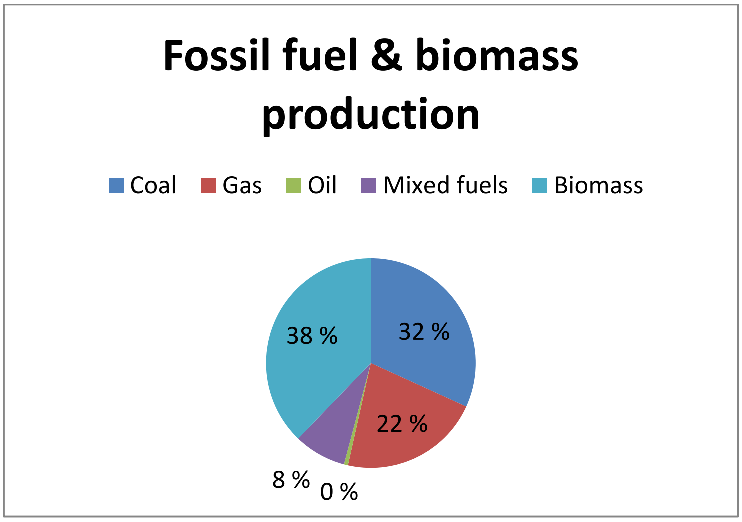


Figure 3 **In Nordic markets 2014, nuclear production was located in Finland and Sweden, most of the hydro production in Norway and Sweden, most of the wind production in Sweden and Denmark and there was hardly any thermal production in Norway. (Data: ENTSO-E)**

Hydropower has a significant role in the Nordic markets. Depending on the hydrological conditions hydropower produces more or less half of the annual electricity production (Figure 2). Most of it comes from Norway which produces virtually all of its electricity with hydropower. Sweden ranks second with over 40 % of installed capacity and the rest is in Finland. What makes hydropower a good part of a power system is the possibility to store water in reservoirs and generate power when it is needed (Figure 7, pg. 14) with low variable costs and virtually zero carbon emissions. Furthermore reservoirs make it possible to level the difference between inflow of water and consumption around the year. In a typical year Nordic reservoirs are filled during late spring-early autumn and emptied during winter (Figure 4). Some of the hydropower plants are run-of-river plants that cannot store the inflow after a rainy period for later use, at least for a long period.

Crampes & Moreaux (2001, 977) note that although hydro power is a renewable resource, in the short term it can be viewed as a nonrenewable resource (limited amount of water in the reservoir) from the economics point of view. Conversely for example fossil fuels are not exhaustible from the producers point of view in the short term although they are nonrenewable resources and depletable in the longer term. Crampes and Moreaux showed that a strategic hydro producer with market power focuses its production in hours when the demand is elastic and reduces it when the demand is inelastic and that in a hydro-thermal setting the presence of a hydro producer switches also the decision making of the thermal producer from a static to a dynamic process. These kind of interactions or dynamic hydro power modelling were not included in this thesis. The use of market power has been studied in Nordic markets for example by Kauppi (2009).

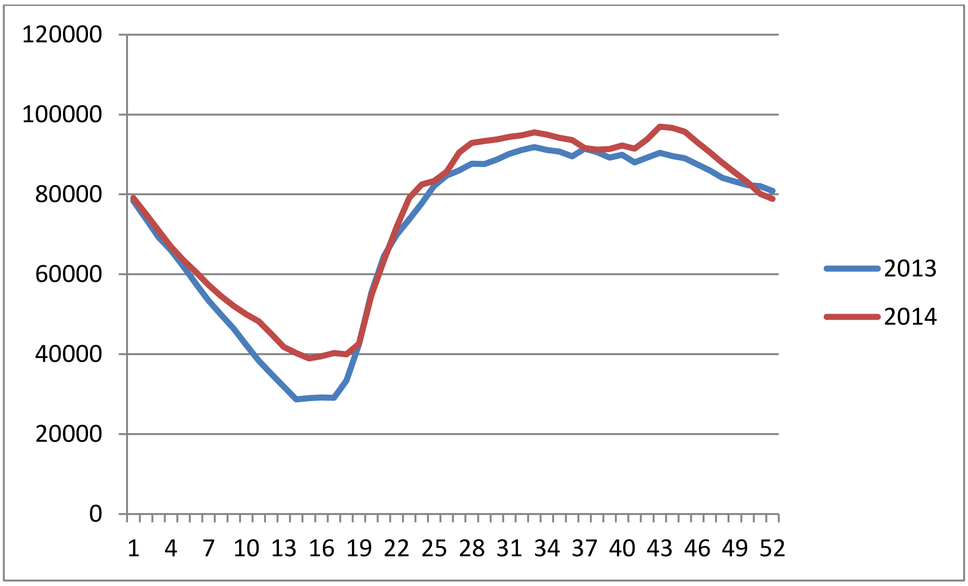


Figure 4 Nordic hydropower reservoirs (GWh) by week in 2013 and 2014 (Data: NordPoolSpot)

Hydro, nuclear, wind and CHP generators produce power currently with lowest marginal costs in the Nordic markets. In general when the demand for electricity increases and more power is needed the more expensive technologies are utilized. Price of electricity is formed at the margin so that the production facility with the highest marginal cost at the moment sets the price (Figure 5).

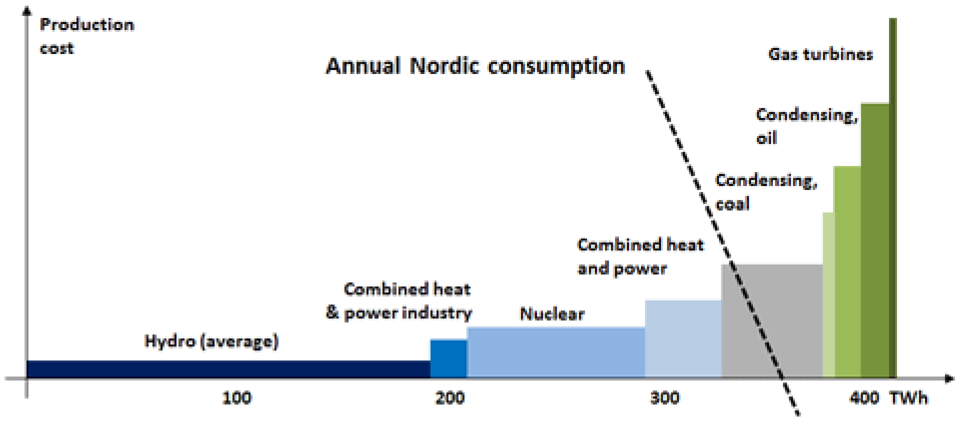


Figure 5 Cost structure and price formation of the markets. (NordPoolSpot)

Consumption of electricity is highest during the cold and dark winter months in Nordic countries (Figure 6). In addition to seasonal differences, consumption of electricity has also a weekly and daily pattern: more electricity is consumed during weekdays than on Saturday or Sunday and more electricity is consumed during the rush hours of the day than in night-time (Figure 7, 14). One challenge of the electricity markets is that production and consumption must be equal at all times as there are not yet large possibilities to store power for later use. This means that electricity must be generated at the time it is used – more in the winter than in summer and more during rush hours than in night-time. In 2013 the peak load of the year took place in Friday morning in the winter (January 25 9 AM, 68 743 GW) (NordReg, 2014, 13).

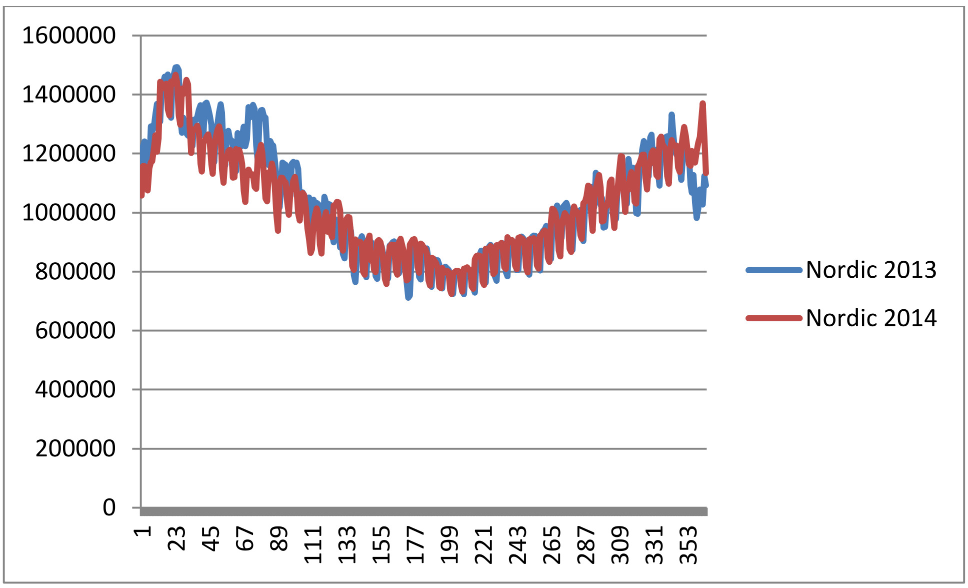


Figure 6 Electricity consumption (MWh) in the Nordic countries daily in 2013 & 2014. (Data: NordPoolSpot)

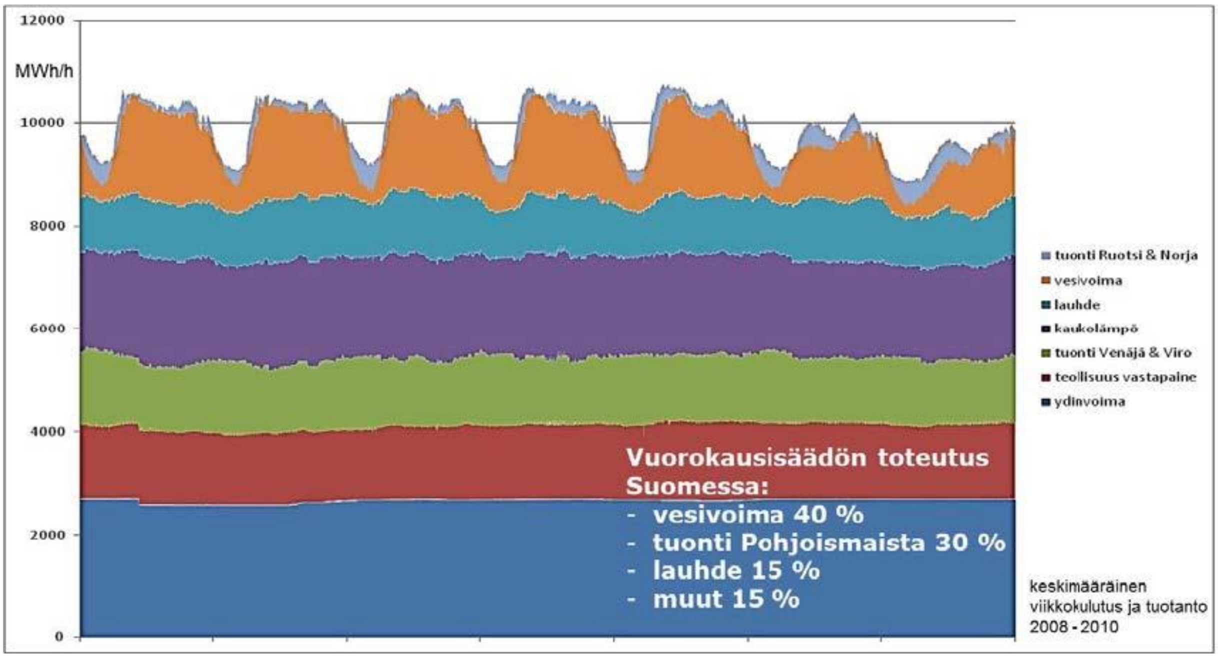


Figure 7 Average weekly consumption and production in Finland 2008-2010. Hydropower production (orange color) fluctuates a lot according to the time of the day in Finland. (Finnish energy, 2016)

Power is transferred in the Nordic grid to balance the supply and demand between different regions. The grid consists of national grids and interconnectors between countries. When the transmission capacity of the grid between different regions is not adequate enough Nordic electricity markets are split into different price regions because of “bottlenecks” in the transmission grid. Ideally there would be only one price area for electricity but this was only true during ca. 23 % of the time in 2013 and this share has been falling in the recent years. Finland formed a common price area with Norway and Denmark 92 %, with Sweden 78 % and with Norway and Sweden 33 % of the time in 2013. (NordReg 2014, 22) There are also interconnectors from the Nordic markets to Western Europe, the Baltics and Russia.

In addition to Transmission System Operators, producers and end-users; distributors, suppliers and traders are key players in the markets. Suppliers buy the electricity directly from the producers or from Nord Pool Spot and then sell it to end-users (e.g. households and companies). Distributors connect the customers to the central grid and provide distribution. Traders and brokers trade electricity deals between producers, suppliers and themselves. There are over 370 producers, around 370 suppliers and around 500 distributors in the Nordic markets. (NordPoolSpot, 2016)

Price of electricity in the Nordic markets is partly driven by climate and weather related variables (in addition to e.g. demand changes, production costs, emission allowance prices (EU ETS) and bottlenecks) (NordReg, 2014, 26-32). Hydropower has the lowest variable costs in the markets and a rainy year or period increases exports from hydro-dominated countries and drives the electricity prices down and vice versa (Liski & Vehviläinen, 2015, 8). The variable inflows affect also other price-dependent production (Figure 8). The increasing amount of intermittent production in the system on the other hand gives more weight on the weather conditions. Temperature affects mainly the demand side – cold temperatures in the winter increase heating energy demand and the peak loads of the year happen in the coldest time of the winter. For example Liski & Vehviläinen (2015) show with empirical analysis that variability of Nordic demand can be explained well by seasons and climatic conditions.

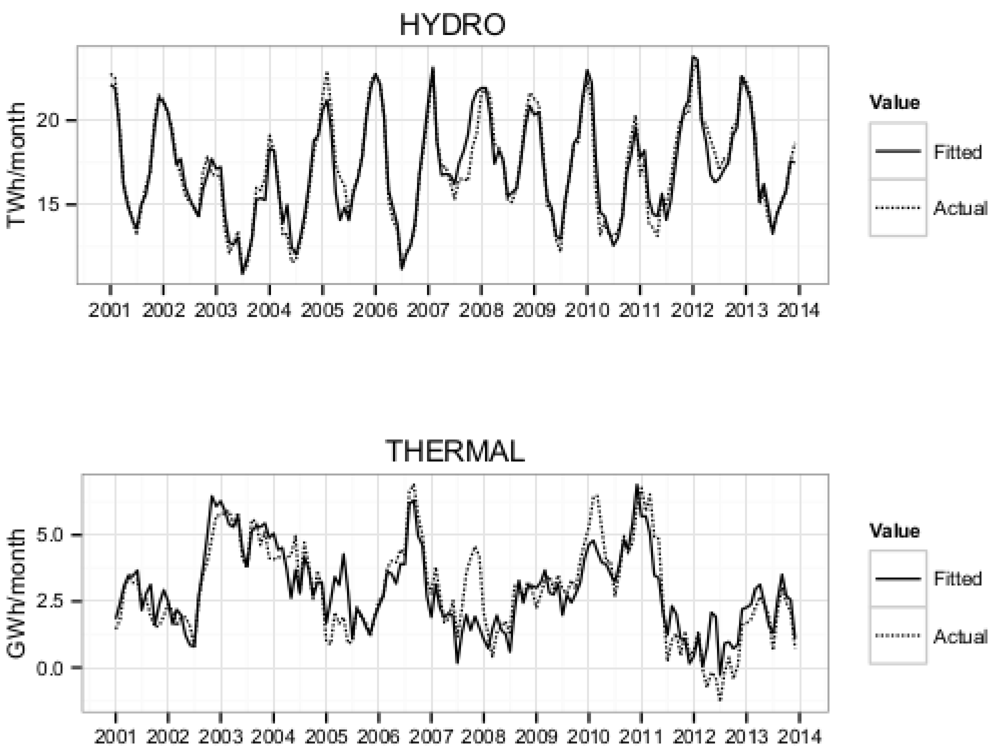


Figure 8 Actual and modelled variation of thermal and hydro power production in Nordic countries in 2001-2013. (Liski & Vehviläinen, 2015, 16)

Figure 9 Nordic power prices and reservoir levels 2000-2014 (Fortum, 2015, 14)

2.2. Climate change policies and the Nordic electricity markets

Three of the four countries (Finland, Sweden and Denmark) in the Nordic electricity markets are part of the European Union and their national climate and energy policies are strongly affected by the EU policies. Norway is also collaborating strongly with the EU on climate change policies. All the countries are part of the United Nations Framework Convention on Climate Change (UNFCCC) and the Kyoto Protocol.

Climate strategies and frameworks in the EU include the 2020 climate & energy package, 2030 climate & energy framework and 2050 low carbon economy. The main targets in the 2020 package are a 20 % cut in greenhouse gas emissions (from 1990 levels), 20 % of EU energy from renewables and a 20 % improvement in energy efficiency. The corresponding targets for the 2030 climate and energy framework are at least a 40 % cut in greenhouse gas emissions, at least a 27 % share for renewable energy and at least 27 % improvement in energy efficiency. The roadmap for 2050 low-carbon economy points to 80 % reductions in greenhouse gas emissions (from 1990 levels).

Nordic countries have also their own targets about climate mitigation. For 2050 these include: a 100 % renewable energy system (Denmark), at least 80 % cut in emissions compared to 1990 (Finland, domestic emissions) and 100 % cut in emissions compared to 1990 (Norway and Sweden, may include offsets). Renewable targets for 2020 final energy consumption (the EU 2020 package) are 35 % for Denmark, 38 % for Finland, 67,5 % for Norway and 50 % for Sweden (OECD/IEA, 2013, 37).

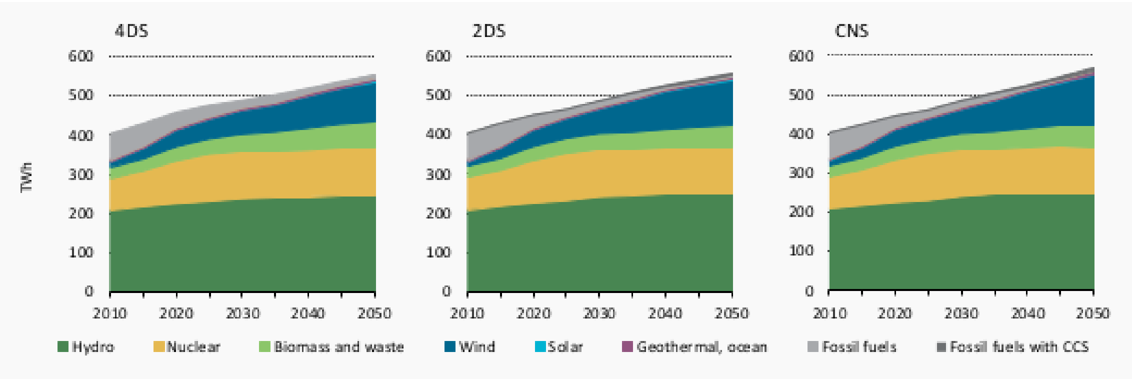
2.2.1. The Emissions trading scheme and renewable energy policies

Energy production is a crucial sector for the climate mitigation policies because of the large amount of greenhouse gases the sector is emitting (IPCC, 2014, 44). EU climate policies are therefore directly affecting the electricity producing sector, including the Emissions Trading Scheme (ETS), binding national renewable energy targets, innovation and research funding and energy efficiency actions. Climate targets are related to also other targets in the energy sector, such as increasing EU's energy security, creating new jobs, advancing green growth and making Europe more competitive. In addition to and in collaboration with EU policies the countries have national policies such as energy and carbon taxes and support policies for power and heat technologies (OECD/IEA 2013, 51).

ETS is a key tool and it covers about 45 % of the emissions in the EU, mostly from power and heat generation and energy-intensive industry sectors (European Commission, 2016b). It is a cap-and-trade system where emitters trade for emission allowances in the emission permit markets. Although the system itself is working, it is not incentivizing significant emission reductions (e.g. Syri, et. al., 2013). This is because there are too many permits available in the markets. High emission prices give an incentive for market players to reduce their emissions and the price of the permits increases if there is scarcity of the permits. Since 2011 there has been cumulatively a surplus of permission permits compared to the emissions of the market participants and according to Aatola, et. al., (2013, 277) the situation is generally thought to continue in the third phase of the ETS (2013-2020). The price of EUA (€/CO_2 ton) was around 5,5-8 euros in early 2016 (EEX, 2016) while at its highest it has been at around 30 euros in 2006 (Aatola, et. al., 2013, 278). At least clean development mechanism, economic recession and an indulgent allocation of emission permits have contributed to the low price (Aatola, et. al., 2013, 277).

Additionally the overlapping between different EU policies (Aatola, et. al., 2013, 8-9) and omitting this issue in the design of the ETS has contributed to the excess supply of emission permits. The purpose of the binding National Renewable Energy Action Plans (NREAPs) is to reach the EU 2020-targets and a 20 % share of renewables in the energy sector in the EU. Each of the countries has different targets depending on their starting point and possibilities to increase the share of renewables. Nordic countries are among the countries with biggest shares of renewables in 2020 in their energy mix in the NREAPs. In general promotion of renewable energy sources displaces more polluting energy sources from the markets. When the total amount of emission permits is not reduced scarcity of the permits decrease (and so does the price) and the effectiveness of ETS is dampened. This is the basic idea behind the problem of these two policies overlapping and the same issue arises also if a country decides to invest e.g. in new nuclear power production.

Renewable energy has increased its share in the Nordic energy mix and this trend is probably going to continue regarding the climate targets and renewable policies of the EU and the individual countries. The main policy to promote this development has been different subsidies for renewable energy (feed-in tariffs or premiums in Finland and Denmark and green certificates in Sweden and Norway). Partly the new renewable energy is thermal (bioenergy) and partly intermittent power (mainly wind). In IEA's scenarios for carbon free Nordic power production 2050 wind power is the fastest growing power technology in the coming decades (Figure 10).



Key point *Growth in electricity generation in all scenarios is covered by low-carbon electricity sources, mainly renewables.*

Figure 10 Different scenarios for carbon neutral Nordic electricity production for 2010-2050 (OECD/IEA, 2013, 62)

In addition to other renewables there is significant potential to increase hydropower production in the Nordic countries. Most of this potential lies in Norway where there is currently potential of about 33,8 TWh/year which has not been protected against hydropower production (Norwegian Ministry of Petroleum and Energy 2015, 27). If all this potential was to realize it would mean about a 15 % increase to the annual hydro power production in Nordic countries and would be more than all the wind production in Nordic countries in 2014 (ca. 28TWh, ENTSO-E). In Finland and Sweden there does not seem to be big potential to increase hydropower production. At least in the National Renewable Energy Action Plans (NREAPs) submitted to EU these countries do not expect significant increases in hydro power production in 2020 (Finnish Ministry of Employment and the Economy, 2010, 18 & Government Offices of Sweden, 2010, 114). In the scenarios for carbon free Nordic energy system 2050 (OECD/IEA, 2013, 163) it is assumed that hydropower cannot expand more than 5 TWh/year in Sweden and 30 TWh/year in Norway until 2050. Hydropower is a beneficial part of the system as intermittent power increases. As noted on page 12 hydropower can adjust its production according to the market situation fairly easily and provide balancing power (Figure 7, 14). Hydropower can for example cut power production in windy days and produce power when it is not windy. In the future some reservoirs might even be pumped to store power when there is excess power in the system, for example a lot of wind power (e.g. Gemini, 2014).

2.2.2. The energy union

Directly related to the electricity markets and climate policies is the concept of Energy Union, a priority of the European Commission. The integration of electricity grids and markets is supposed to increase energy efficiency, secure the supply, help integrate intermittent production to the market and cut emissions (European Commission, 2016). Relating to this development connections from the Nordic area to Continental Europe have been increasing. Besides the overall benefits of larger markets Nordic hydro reserves are hoped to work as a "green battery" and provide balancing services for power systems in Europe (e.g. Gullberg, 2013). For example, a new interconnector (Skagerrak 4, 700MW, 2014) between Norway and Denmark nearly doubled their exchange capacity and new interconnectors between Norway and UK (The NSN, 1400MW, 2021) and Norway and Germany (NordLink, 1400MW, 2020) are being built. A new interconnector between Finland and Estonia (EstLink2, 650MW, 2014) more than doubled their exchange capacity in 2014 and a new interconnector between Sweden and Lithuania (NordBalt, 2015/2016) is being built. This trend can be expected to continue and the main driver for this is the integration of new renewable intermittent production to the grid according to the ENTSO-E's Ten Year Network Development Plan 2014 (ENTSO-E, 2015). For example the new interconnectors from Norway to Germany and UK are supposed enhance the interplay of hydropower in Norway and intermittent power in Germany and UK (Statnett, 2015ab). This kind of exchange is already taking place between Denmark and Norway as Denmark exports excess wind power in windy days to Norway and imports hydro power from Norway when it is not windy (e.g. Green & Vasilakos, 2011).

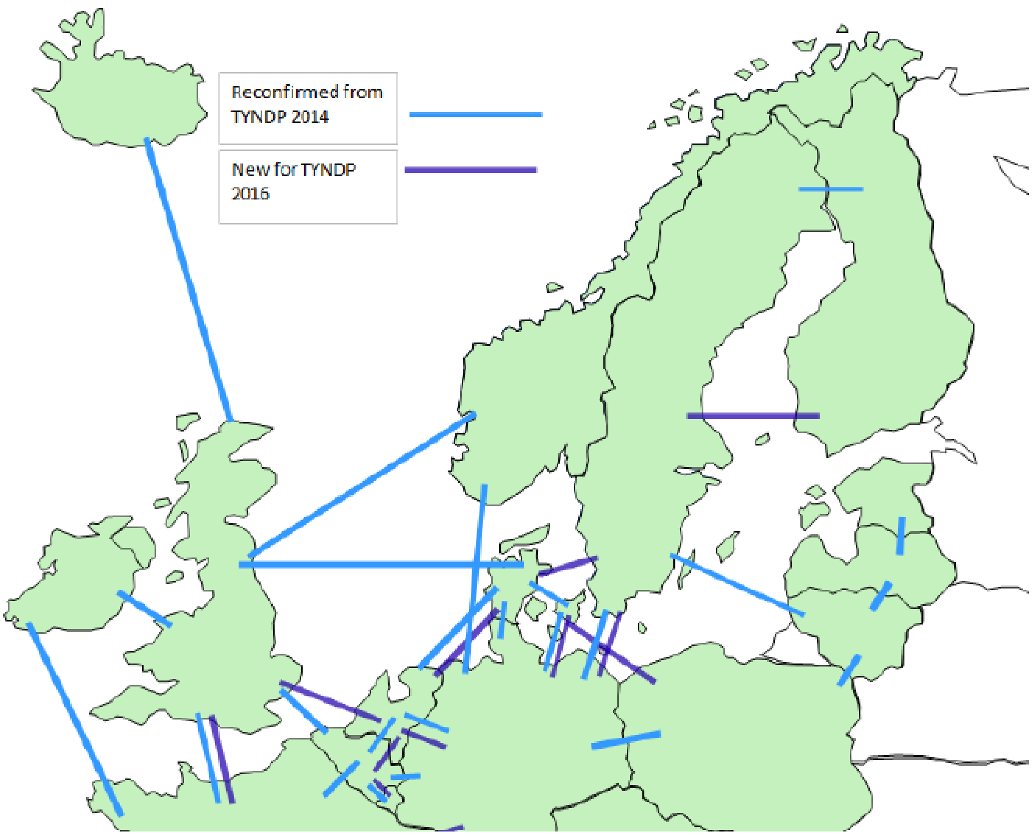


Figure 11 New interconnectors unite European power markets. Border projects (mid-term, long term and future) that are commissioned 2020-2030 and onwards in the Ten Year Network Development Plan 2015 by the Entso-E (Entso-E, 2015, 37)

2.2.3. The security of supply

Although intermittent power substitutes other power generation, the wind is not always blowing and the sun does not always shine. Intermittent power increases the need for balancing power which is at the moment provided by hydro and thermal production in the Nordic countries. With regards to German example (see e.g. Poser, et. al., 2014, 58) there is a concern that intermittent production will make thermal balancing power production capacities unprofitable and endanger the security of supply so mechanisms to keep these facilities available are being discussed. According to Fortum, a Nordic energy producer and supplier, "the increase of renewable generation, combined with poor general economic performance, weak power demand and low emission allowance prices, has depressed wholesale electricity prices. For these reasons, much of the commercial flexible power generation, which is able to balance the increasing intermittency in the power system, is barely profitable (or even unprofitable) and has been closed down." (Fortum, 2015, 16) Eurelectric, the European electricity industry union, states in their report "A Reference Model For European Capacity Markets" (Eurelectric, 2015a) "that properly designed capacity markets, developed in line with the objective of the IEM, are an integral part of a future market design." The term IEM refers to Internal Energy Markets – integrated European energy markets (Energy union). In capacity markets the objective is system adequacy and production availability is the product. They are designed to provide incentives for enough production capacity and work alongside the basic electricity markets. (Eurelectric, 2015a) According to Fortum capacity market design is an option that possibly needs consideration in the Nordic markets to ensure long term investments in power generation (Fortum, 2015).

2.2.4. Electricity efficiency and electrification

Electricity demand is a major theme in climate change mitigation and increasing energy efficiency is one of the climate change mitigation strategies in the energy sector. EU's target is to increase energy efficiency by 20 % by 2020 and by 27 % by 2030 compared to the projected use of energy in 2020 and 2030. For example in Finland buildings account for almost 40 % of energy use and regulations have directed the sector significantly to more energy-efficient direction (Lemström, 2015).

Electricity efficiency could increase also if customers could respond to market conditions more by allocating their consumption according to changing supply and demand. It is a common problem in electricity markets that customers do not have incentives to avoid using electricity in the peak hours (price does not vary according to when electricity is used). If the price of electricity is the same all day long there is no economic sense to avoid electricity use in the peak consumption hours of the day and thus more generation capacity is needed in the system. Real-time pricing (RTP) means that electricity customers are billed by the hour which makes it more expensive to use electricity in the peak hours. Maria Kopsakangas-Savolainen and Rauli Svento (2012) have studied the introduction of real-time pricing in Nordic power markets. They show that increased elasticity in consumption combined with a greater share of real-time pricing decreases the need for capacity. Real-time pricing is however not clearly an electricity conservation program although it has the potential to increase efficiency in the markets (Borenstein, 2005, 11) – depending on the case it might increase or decrease consumption or emissions. Big investments have been made to smart meters in the Nordic countries and they are part of EU's energy efficiency policies but according to Fortum the Nordic retail market does not yet give enough incentives for demand response or other small scale actions (like solar production) (Fortum, 2015). Demand response could be even more important from the efficiency point of view when more intermittent power is integrated to the system and price volatility possibly increases. RTP could be a significant way to promote wind power in the Nordic power markets (Kopsakangas-Savolainen & Svento 2012, 1140).

Electrification is also a trend in the energy sector related to climate mitigation. Electrification means replacing other sources of energy with electricity. Electric cars are a good example – in order to decrease emissions in the transport sector large transformation of the car fleet to electric cars might occur in the future. In this way consumption of electricity might increase although overall energy emissions could decrease because of fuel switching. Switching to heat-pumps and electric heating is another good example. Electrification is happening in the Nordic countries: for example in Norway 16 % of new sold cars in 2014 were electric cars or hybrids, in 2012 nearly half of Swedish homes had an electric heat-pump of some sort and in Finland there is a pilot program where households can substitute oil heating with electric heating using smart meters that are connected to NordPoolSpot markets and warm the house when the spot price of electricity is low (Eurelectric, 2015).

To conclude, electricity markets are going through big changes regarding the generation and use of electricity and the distribution of electricity between countries. This is necessary to keep in mind when the impacts of climate change to hydro power production and indirect impacts of climate change are studied. It is nevertheless safe to say that hydro power plays an important role in Nordic electricity markets also in the near future, possibly even more when new intermittent production enters the markets.

One vision for future energy markets is provided by a Finnish strategic research project funded by Tekes (Finnish funding agency for innovation), Neo-Carbon Energy, that paints a future energized by renewables. Their energy solution is based on three building blocks: renewables, neocarbonisation and storage. Solar and wind are the main renewable energy sources in the vision and neocarbonsation means using carbon in a new way to carry energy: by using the atmospheric carbon to produce synthetic hydrocarbons. Hydrocarbons are still needed in the future as all energy use cannot be fulfilled with electricity. Storage plays also a big role along with demand flexibility to deal with the intermittency of solar and wind production. (Neo-Carbon Energy, 2016)

2.3. Climate change impacts on electricity markets

Climate change can affect the electricity markets and more widely energy markets in many ways. Ciscar & Dowling (2014) list earlier literature on the subject and changes that would ideally be studied when impacts of climate change to energy sector are modelled. These include both changes to demand and supply of energy as well as other changes in the energy sector.

Most important impact to the demand of energy might be that on heating and cooling of spaces. Warmer temperatures can increase the need for cooling or decrease the need for heating depending on the location and season. Changes to supply of energy include various changes to power generation. Thermal and nuclear power production can be affected because of changes in cooling water temperature and availability and hydropower potential can change because of changing evaporation, absorption and precipitation. Supply and cost of biomass and bioenergy and wind and solar power production can also change because of changing conditions. Other possible impacts to energy systems include for example accessibility to resources (e.g. changes in mining conditions), new transport pathways (e.g. new shipping routes through the Arctic) and impacts to infrastructure (e.g. electricity transmission). Infrastructure could be affected by extreme events (e.g. storms, floods) or changing natural conditions (e.g. sea-level rise, icing). Also electricity transformers or conductivity of power lines could be affected because of changing conditions.

Ciscar & Dowling list different economic and engineering models which have been used to study climate change impacts on energy sector and note that they only capture a subset of impacts mentioned above. For example Mima & Criqui (2015) used the POLES model, a bottom up engineering based global energy model, to study costs of climate change to European energy system by changes in heating and cooling demand and impacts on nuclear, thermal and hydro production. Results are "preliminary and uncertain" but show that climate change will affect demand and supply of energy in Europe and diversely in different regions (Mima & Criqui, 2015, 317). Below impacts on renewable energy production and cooling and heating demand are further but still briefly discussed along climate simulations for Nordic countries before focusing on the main issue of this thesis, impacts on hydropower production.

2.3.1. Impacts on renewable power production

Climate and energy systems: Risks, Potential and Adaptation (CES) (Nordic Council of Ministers, 2012) was a project funded by the Nordic Energy Research to study the impacts of projected climate change on the Nordic and Baltic renewable energy sector. The project involved "nearly 100 scientists and 33 institutions in all Nordic and Baltic countries" and ran from 2007 to 2010 (Nordic Council of Ministers, 2012, 9).

In CES climate change impacts were studied using various climate scenarios from different climate models. On a relatively small geographical area such as Nordic or Baltic countries Global Circulation Models (GCM's, a type of global climate model) draw a too coarse picture and Regional Circulation Models (RCM's, a regional model) are used to make projections more accurate (25km horizontal resolution). Even when RCM's are used, there are still large uncertainties in the simulations. Climate scenarios were produced in collaboration with the European FP6-project ENSEMBLES (van der Linden & Mitchell, 2009). All the scenarios were produced using the emission scenario SRES A1B. It is argued in the report that the relatively short time frame considered in the study leaves little space for uncertainty related to different emission scenarios. (Nordic Council of Ministers, 2012, 36-37)

Seven different GCM’s were downscaled with eleven different RCM’s to produce different climate scenarios. Out of these simulations three were recommended to be used in CES as some working groups studying the impacts of climate change had a limited maximum number of scenarios that they can study. The three different simulations were all using different CGM’s and RCM’s. (Nordic Council of Ministers, 2012, 37)

The results of the 15-member multi-model ensemble, a combination of different models to deal with the variation in results, are illustrated in the report and presented as 30-year averages (1961-1990 and 2021-2050). The temperature changes in the Nordics between the periods are generally larger in the winter (1-4 degrees Celsius increase) than summer (mostly less than 2 degrees Celsius increase). Precipitation is projected to increase throughout the Northern Europe again more strongly in the winter (10-20% increase over the Scandinavian region) than in the summer. (Nordic Council of Ministers, 2012, 38)

The study group focusing on climate change impacts on wind conditions found the changes to be small and within a 5 % range. Another group focusing on bio-fuel production potential found that climate change along with thinning regime changes could significantly increase bio-fuel production potential (in Finland). The hydrology group found that climate change impacts on hydrology and river runoff can be expected to be significant but uncertainties are large. Simulated changes are in general increases in runoff and more in the winter than in the summer with earlier and smaller spring floods, although rain floods could occur more often. (Nordic Council of Ministers, 2012, 14-16)

2.3.2. Impacts on electricity demand

The impact of climate change on heating energy demand can be significant. For example in Jylhä et. al. (2015) it is estimated that heating energy demand could decrease 3 % per decade in the period 2020-2050 (compared to 1960-1990 climate baseline) in Finland. In Seljom et. al. (2011, 7316) heating energy demand is estimated to be 7-10TWh/a smaller in 2050 in Norway depending on climate scenario and compared to the no climate change baseline. In De Cian et. al. (2013) cold countries' electricity demand reduces because of warmer temperatures in 2085. Climate change can also increase demand in the summer period because of warmer summers and more need for cooling but the warming of the winters is generally thought to have a larger impact in Northern Europe (e.g. Pilli-Sihvola, et. al., 2010; De Cian, et. al., 2013; Mima & Criqui, 2015). Like in all climate change impact studies uncertainties concerning the future climate are significant (as well as projections about social and technical development) (Jylhä, et. al., 2015, 114).

As in the supply side the direct impacts of climate change on the electricity demand of a trading partner could have an indirect impact to Finland. For example in Seljom et. al. (2011) climate change impacts on Norwegian energy system are studied with the MARKAL model and the rising winter temperatures (less heating electricity demand) contribute to excess production in Norway and an increase in energy exports. Similarly as increasing precipitation because of climate change, decreasing electricity demand could increase exports from Norway which means also hydropower in practice.

Table 2 Climate change-related changes in electricity demand.

Climate change mitigation's and impacts' effect on electricity demand

Increases demand	Decreases demand
Increased summer cooling demand, Electrification	Decreased winter heating electricity demand, Electricity efficiency

2.4. Climate change impacts on hydropower potential in the Nordic countries

The work of the Hydropower-Hydrology group of CES relied largely on national research programs and therefore the methodologies, focus and databases were not identical in every study. The studies were based on ensembles of regional climate models although different studies used different regional climate scenarios. (Nordic Council of Ministers, 2012, 113) In spite of the large uncertainties in modelling future climates and hydrological simulations it is stated in the report that “there is little doubt that the Nordic and Baltic hydropower systems will be affected strongly by a changing climate” (Nordic Council of Ministers, 2012, 141). Climate change will alter the seasonal inflow from place to place due to e.g. precipitation changes, glacier melt, changes in evaporation and winters becoming wetter and milder. The results show that generally the potential for hydropower will increase while there might be increased water shortages during summer season in some areas. Also due to milder winters the large snow-melt spring floods are likely to become more seldom (Nordic Council of Ministers, 2012, 141). Besides studying the impacts on hydropower production there was a focus on regulation of lakes and rivers, extreme floods, dam protection and design floods for high hazard dams.

According to the report uncertainties of the changes are large and the results are dependent on the choice of regional climate scenario. In the CES project as many as 20 different climate scenarios were used in some projects and ensembles were used to visualize these uncertainties. In addition to the choice of the climate scenario there remained uncertainties concerning also other techniques such as the choice of the hydrological model and the interface methods to combine climate and hydrological models. According to the report “it is of utmost importance that these uncertainties are communicated properly to decision makers”. (Nordic Council of Ministers, 2012, 116)

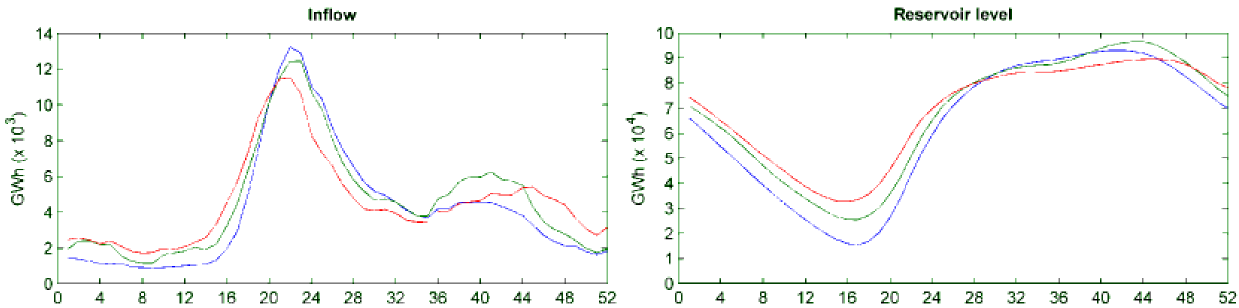


Figure 12 **Inflow and reservoir figures during year (weekly) in reference climate scenario (blue line) and two climate scenarios (green and red line) 2020-2050. (Nordic Energy Research, 2012, 185)**

The inflow data from the work of the hydrological working group was used in a separate study in CES studying the climate change impact on the Nordic electricity system with the focus on the NordPool market. A research group from SINTEF energy research (Norway) used the EMPS-model that also “most major players in the NordPool market” use for market analysis (Nordic Council of Ministers, 2012, 179). Changes to the future power system were studied with changes in two climate variables: temperature and inflow. Power system forecast (2020 system) was based on forecasts in production and transmission capacities, electricity demand, input fuel costs and CO_2-quota prices and changes in climate variables were based on simulation research in the CES project. Impacts were compared to the reference climate (1961-1990) that was based on observed weekly inflow, temperature and wind speed. Investments to new production or transmission capacities were not accounted in the model. (Nordic Council of Ministers, 2012, 179)

Hydro production increases significantly in the two different climate change scenarios compared to the reference climate (9,4 – 10,3 %, Figure 13 below). In the climate change scenarios inflow of water to reservoirs and the reservoir levels are also more even between seasons than in the reference climate scenario (Figure 12). Increases in production are divided more evenly during the year than the changes in inflow would suggest and are smaller because of more spillage.

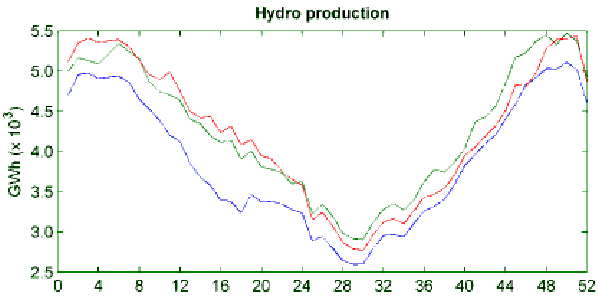


Figure 13 Hydro production during year in a reference scenario (blue line) and two climate scenarios (red and green line) in 2020-2050. (Nordic Energy Research, 2012, 185)

According to the results hydro production increases more in Sweden (ca. 10,7 %, +6TWh/year) and Norway (ca. 12,5%, +13TWh/year) than in Finland (ca. 5,4%, 0-1 TWh/year). Thermal (condensing & nuclear) production decreases in all countries and mostly in Finland (6,6-7,1 TWh/year) and Denmark (5,4-5,6 TWh/year). According to the results exports of electricity decrease from Denmark and increase from Sweden while imports to Finland increase and Norway switches from an importer to an exporter. Overall exports from Nordic countries to Continental Europe increase. (Nordic Council of Ministers, 2012, 184-187) Finland is thus affected by climate change although hydropower production is not as much affected as in Sweden and Norway. The results indicate that when the impacts of climate change to hydropower production and to electricity markets are thought as direct and indirect impacts, indirect impacts from Sweden and Norway to Finland outweigh the direct impacts to Finland. The change in temperature and electricity demand was also studied and contributed to the results.

There are also other studies focusing on climate change impacts on hydrology in Scandinavia some of which are presented in the following table (Table 3, pg. 31-32).

Table 3 Different studies focusing on climate change impacts on hydrology in the Nordic countries.

Reference (Year)	Model(s)	Scenario	Geographical area	Time period (Reference)	Impacts	Other
Lehner et. al (2005)	Global hydrological WaterGAP-model, GCM-model ECHAM4	Baseline A (slightly above A1B SRES)	Europe	2020	Change in developed hydropower potential (%): Finland 12,7; Sweden 6,8; Norway 9,8	In this Europe wide study, Scandinavia and northern Russia increase their hydropower potential, while in many countries it is decreased
				2070	Change in developed hydropower potential (%): Finland 24,3; Sweden 16,1; Norway 19,4	
	Global hydrological WaterGAP-model, GCM-model HadCM3			2020	Change in developed hydropower potential (%): Finland 5,1; Sweden -4,9; Norway -3,9	
				2070	Change in developed hydropower potential (%): Finland 18,6; Sweden 20,0; Norway 25,3	
Nordic Council of Ministers(2012)	DMI(Institute)-HIRHAM(RCM)-Echam5(GCM)	SRES A1B	Nordic region	2021-2050 (1961-1990 climate model run)	Increase in inflow 12 %	44,8 % increase in winter and a 4,5 % in summer. Strongest inflow increase in winter in Norway
	met.no(Institute)-HIRHAM(RCM)-HadCM3(GCM)				Increase in inflow 10,8 %	88,6 % increase in winter and 7 % decrease in summer. Strongest inflow increase in winter in Norway
Seljom et. al. (2011)	Five different GCMs (ECHAM4, HadAM3H, BCM v 1 & v 2, CAMSOslo) and one RCM (HIRHAM)	SRES B2, A2 & A1B, CMIP2, IS92a,1,63xCO_2	Norway	2005-2050 (2005 present climate)	Hydropower potential will increase by 3,7-13,5 % depending on the scenario (model & emission)	Inflow is smaller in the reference run except for summer weeks

Olsson et. al. (2015)	Four different GCMs (ARPEGE, BCM, ECHAM5, HadCM3Q0) and four different RCMs (HIRHAM5, REMO, RCA, HadRM3Q0), hydrological model WSFS	SRES A1B	Four catchments in Finland	2050-2091 (1961-2000)	Change in mean annual runoff varies between -15 – +26% between different model runs and regions. Median change + 6 %.	Increasing winter discharges, decreased and earlier spring discharge peaks, and decreasing summer discharges
Veijalainen et. al. (2012)	Different GCMs (19 GCM mean, CCSM3(NCAR), ECHAM5/MPI-OM, HadCM3-Q3, ARPEGE) and RCMs (RCA3, HIRHAM)	SRES A1B	Finland	2010-2039 & 2040-2069 (1971-2000)	On average increase in inflow 1-3 % (2010-2039) and 6-8 % (2040-2069). Large deviation between different model runs.	Increase in winter, decrease to small increase in summer. Changes geographically significant.
Veijalainen et. al. (2012)	Four scenarios with different GCMs (ECHAM5, HadCM3 low & mean, ARPEGE) and RCMs (REMO, RCA3, HadRM, HIRHAM), WSFS hydrological model	SRES A1B	Four catchments in Finland	2060-2099 (1961-2000)	Change in mean annual discharge approximately 10-14 %	Seasonal variation the most consistent in the results. Large deviation in the results between climate runs and catchments.
Graham et. al. (2007)	Seven RCM's, two GCM's, HBV hydrological model, linear regression method to assess hydropower potential	SRES A2 & B2	Lule river basin in Sweden, where 20 % of Swedish hydro power is produced	2071-2100 (1961-1990)	The range of increase in hydropower potential is from +18% to +59% and the ensemble mean is +34%.	Generally: simulated discharges increase more in winter, spring floods come earlier and are milder and summer discharges even decrease

There is wide variation in the results of different studies as well as in the studies themselves depending on different models, scenarios and time scales. For example impacts to Finland vary from relatively small changes (and even decreases) to 24,3 % increases in hydropower potential. Variation is also highlighted in the studies and relevant concerning any climate scenario – uncertainties are significant. Although predicting the future is impossible and the uncertainties are large, in CES-studies as well as in other studies cited in the table, generally the changes point to more hydropower potential and changing yearly patterns (inflow increases relatively more in the winter). It is also notable that there is much more hydro power in Sweden and Norway than in Finland to begin with when looking at the results. A 5 % increase in 2014's hydropower production would have meant 650 MWh's in Finland and 6850 MWh's in Norway.

3. Methods

3.1. The electricity market model

A model by Kopsakangas-Savolainen and Svento (2012) was used to simulate the Nordic electricity markets in this thesis.[1] The model is based on the theoretical model by Borenstein (2005) that is made to study the effect of Real-Time Pricing (RTP) in electricity markets and Kopsakangas-Savolainen and Svento applied this model to the Nordic electricity markets (Kopsakangas-Savolainen & Svento, 2012). They have also used the model to study different hydro production strategies, economic value of intermittent power production and the promotion of intermittent power production in the Nordic markets (Kopsakangas-Savolainen & Svento 2013a, 2013b & 2013c). The following introduction of the model is based on the articles by Kopsakangas-Savolainen & Svento (2012, 2013a, 2013b, 2013c) and on the original model and article by Borenstein (2005).

The model simulates Nordic power markets throughout the year (hour by hour) to find the long term equilibrium of supply and demand. Supply is modelled to represent five different technologies: nuclear, hydro, wind, midmerit and peak power technologies. Producers and retailers are assumed to be competitive and their profits are assumed to go to zero (capacity constrained technologies are allowed to earn profits). Demand is modelled as a constant elasticity of demand for customers in real time pricing (hourly pricing) and those paying a flat rate for the whole year. After the demand function has been constructed for the whole year hour by hour, supply side is calculated hourly by expanding every technology's capacity until its profits go to zero or the capacity limit (hydro & nuclear) is reached. Small marginal investments (1 MW) are made at the margin to fulfil the demand. Next the flat price of the markets is adjusted so that profits of the retailers go to zero. With the adjusted flat price the structure of producers are again calculated and these two loops run as long as the resulting price level drives the profits of both producers and retailers to zero. This is then the long-run structure of power markets with given assumptions about technology and customers.

[1] The model was run in Matlab and I received the code from and ran it with the help of Maria Kopsakangas-Savolainen and Hannu Huuki in early 2016.

3.2. Demand in the model

A constant elasticity of demand is assumed in the model. The demand function is not estimated but built around the load duration curve of the Nordic markets. An 'anchor-point' is calculated for each hour of the year to scale the demand to the load duration curve. These anchor points are then brought to the demand function to represent the different hourly demands of the year (8760 hours). The anchor point is calculated by $A_h = D_h/p_c^{\varepsilon}$, where A = anchor point, h = hour, D = demand, p_c = a constant price and ε = the price elasticity of customers. (Kopsakangas-Savolainen & Svento, 2013c, 144) The constant price is an assumption but the shape of the load duration curve is what matters more (Borenstein 2005, 5). In this study the average Nord Pool Spot system price for 2014 was used (29,1€/MWh; NordPoolSpot, 2016).

The load duration curve shows the annual consumption hour by hour from the hour with the highest demand to the hour with the lowest. The load duration curve for year 2014 is used which is good to keep in mind: demand is represented by the year 2014. 2014 was chosen mainly because of fresh data and because the year was warm and thus possibly fits the context of climate change well. In 2014 the hour with the highest demand (hour #1 in the curve) had more than two and half times the load of the hour with the lowest demand (hour #8760 in the curve).

There are two types of customers in the model and in the demand function. Some customers are billed by a flat rate for electricity through the year while RTP-customers are billed by the hourly price which varies through the year. The share of customers in RTP (α) and price elasticity (ε) are exogenously input to the model. Kopsakangas-Savolainen & Svento (2012) analyzed the introduction of real-time pricing to Nordic markets and studied the effects of different shares of customers in RTP and different price elasticities.

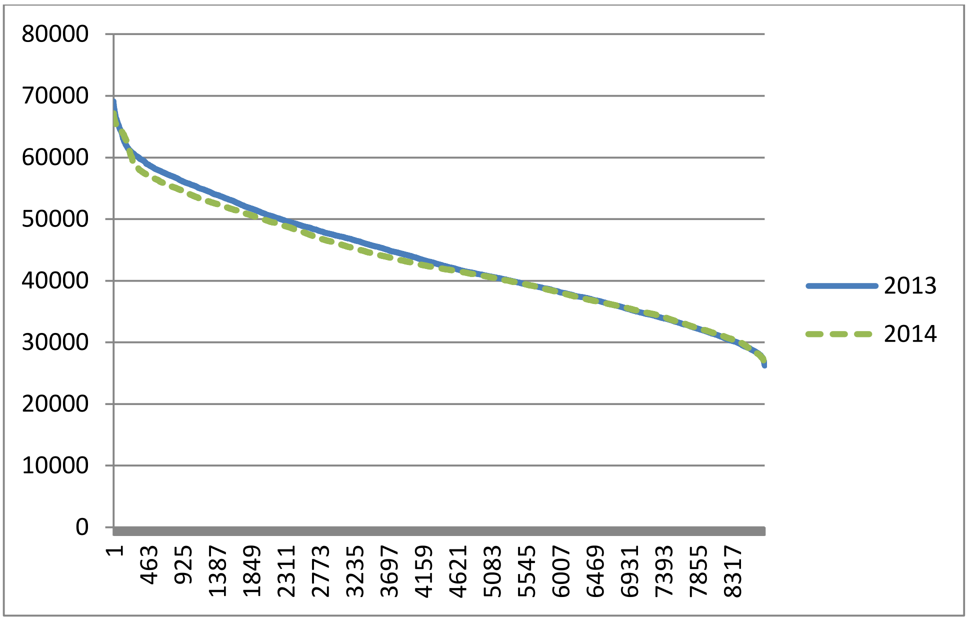


Figure 14 Load duration curves of Nordic countries in 2013 and 2014. MWs in y-axis and hours in x-axis. (Data source: NordPoolSpot)

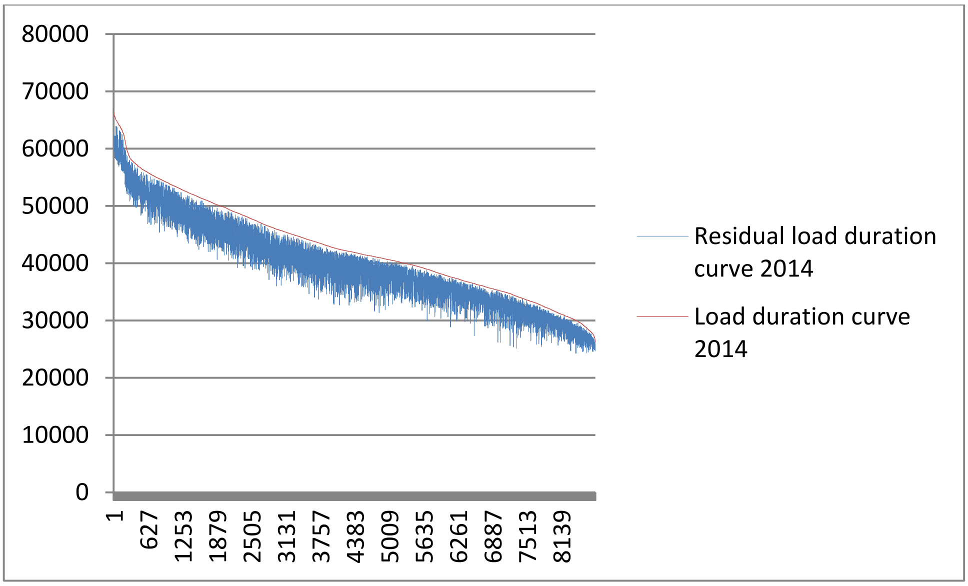
The aggregate demand for an hour for a price and price elasticity is $D_h(p_r) = A_h p_r^{\varepsilon}$. For the customers in RTP the demand is $D_h(p_r) = \alpha p_r^{\varepsilon} A_h$ and for customers in flat pricing it is $D_h(p_f) = (1-\alpha) p_f^{\varepsilon} A_h$, where α is the share of customers in RTP, ε the price elasticity of customers, p_r the retail price of electricity for RTP customers and p_f the retail price for non-RTP customers. The aggregate demand function for an hour is thus (Kopsakangas-Savolainen & Svento, 2013c, 144):

$$D_h(p_r, p_f) = [\alpha p_r^{\varepsilon} + (1-\alpha) p_f^{\varepsilon}] A_h, h = 1, \dots, 8760. \quad (1)$$

3.3. Production and retail sectors in the model

In the model five types of producers are generating power. Production consists of nuclear, hydro, intermittent, midmerit and peak power technologies. Hydro, nuclear and wind generators are capacity constrained whereas the capacities of midmerit and peak power technologies' are solved in the model. Midmerit and peak power technologies represent the thermal (biomass, peat, gas) production in the model. Midmerit power has higher investment costs than peak power but peak power's fuel costs are lower. Nuclear power is produced evenly through the year (base load). Hydropower is modelled also mostly like nuclear power but with the exception that if an hour's demand is smaller than the combined nuclear and hydropower production excess hydropower is allocated to the later hours. This way in the model nuclear power produces base load power, midmerit and peak power produce balancing power and hydro power produces partly both.

In this approach intermittent production can be treated by subtracting it from the load duration curve (Lamont, 2008). In Figure 15 the hourly wind production of the Nordic countries is subtracted hour by hour from the load duration curve. As seen in the figure 15 (pg. 37) wind power contributed significantly to power production in 2014 but also the intermittency of it is clearly visible - the production varies a lot from hour to hour. In 2014 27 958 TWh of electricity was produced by wind power and divided for all hours it makes 3191 MWh per hour (installed capacity was 9653MW in 2013, see Table 1, pg. 10). According to the data used lowest wind power production per hour was 110 MW and the highest was 9931 MW. At its highest wind power produced 26 % of the hourly electricity consumption and at its lowest 0,3%.



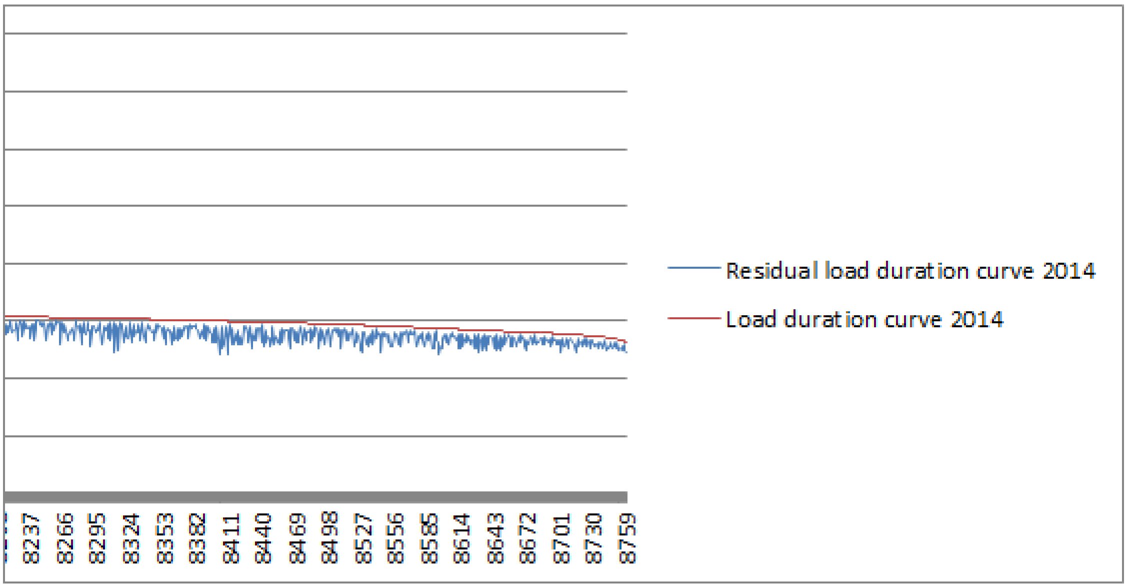


Figure 15 Load duration curve for year 2014 after subtracting wind production and a more close-up picture below to visualize hour-to-hour variation. MWs in y-axis and hours in x-axis. (Data sources: NordPoolSpot, Finnish energy, Svenska kraftnät)

It is assumed in the model that both generators and retailers work in competitive markets and that both of the sectors maximize profits. Profit functions of the sectors are (Kopsakangas-Savolainen & Svento, 2013c, 144):

$$\pi_R = \sum_{h=1}^{8760} \left[(p_f - w_h)(1-\alpha)D_h(p_f) + (p_r - w_h)\alpha D_h(p_r) \right] \qquad (2)$$

$$\pi_G = \sum_{h=1}^{8760} (w_h D_h - cD_h) - rK \qquad (3)$$

where R = retail sector, G = generation sector, w = wholesale price, c = marginal generation costs and rK = annual capital costs

Again, retail sector sells the energy to customers in real-time pricing (α) for different price (p_r) than the flat rate (p_f) that the rest of the customers pay. The demand and profit functions (1, 2 and 3) are used to solve the short and long run equilibriums of the power markets.

3.4. Describing the equilibrium with only one technology

Kopsakangas-Savolainen & Svento (2013c, 144) demonstrate the model by describing it with only one technology. Short-run profits of generators by hour are maximized in equation 4, which is same as the equation 3 but without capital costs (Kopsakangas-Savolainen & Svento, 2013c, 145).

$$\pi_G^{SR} = w_h D_h - cD_h \tag{4}$$

Because the profits are assumed to go to zero the result is $w_h = c$. The wholesale price of electricity is the same as the marginal cost of producing electricity when the demand is not greater than the capacity limit (like D_i and D_j in Figure 16). If the hourly demand (like D_k in the Figure 16) exceeds the short-run capacity limit (K_{tot}^{SR}) real-time pricing adjusts the price level (p_r) to match the supply and demand (Kopsakangas-Savolainen & Svento, 2013c, 145).

$$D_k = \left[\alpha p_r^{\varepsilon} + (1-\alpha)p_f\right]A_h = K_{tot}^{SR} \tag{5}$$

$$p_r = \left[\frac{K_{tot}^{SR} - (1-\alpha)p_f A_h}{\alpha A_h}\right] \tag{6}$$

So if the demand is smaller than the short-run capacity limit the wholesale price is same as the marginal cost. When the demand exceeds this limit the wholesale price is determined by real-time pricing (Kopsakangas-Savolainen & Svento, 2013c, 145).

$$w_h = c \; when \; D_h \leq K_{tot}^{SR} \tag{7}$$

$$w_h = p_r \; when \; D_h > K_{tot}^{SR} \tag{8}$$

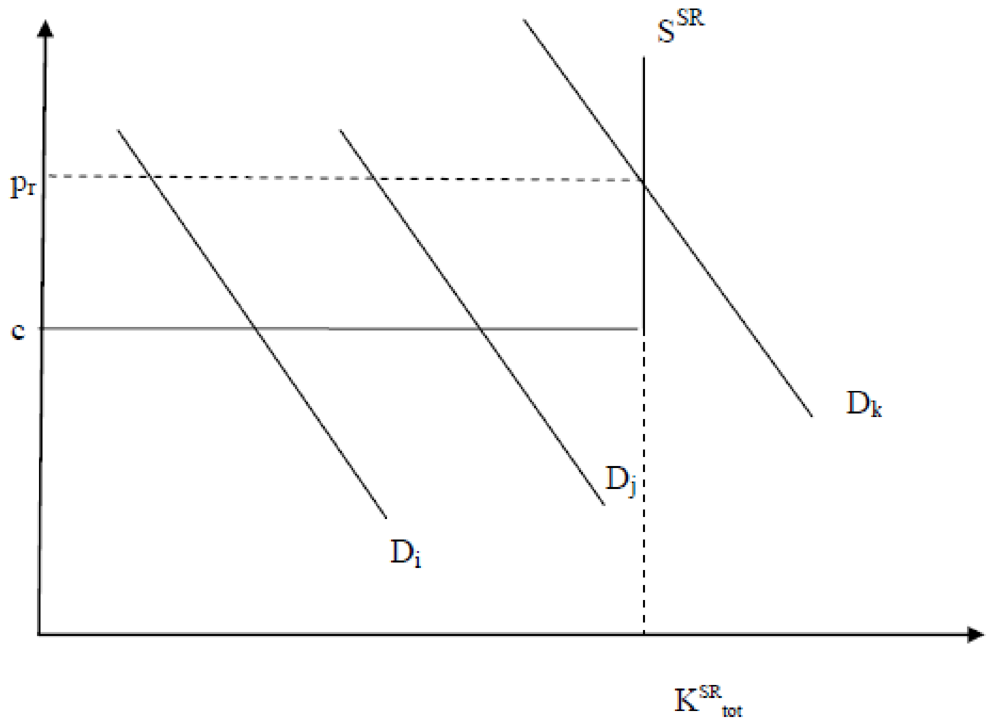


Figure 16 Production with only one technology and a capacity limit (K^{SR}_{tot}). When demand is higher than capacity limit (like D_k), real-time pricing determines the price level (p_r) (Kopsakangas-Savolainen & Svento, 2013a, 15)

After the capacities and prices are known the flat rate is solved. The costs of retail and transmission are not taken into account in the analysis and the profits of the retail sector are assumed to go to zero because of competition. Flat-rate price is then the weighted average of the real-time wholesale price. Real-time price of the retail sector is the same as the wholesale price of electricity. (Kopsakangas-Savolainen & Svento, 2013c, 145)

$$(1-\alpha)\sum_{h=1}^{H}(p_f - w_h)D_h(p_f) = 0 \qquad (9)$$

$$p_f = \frac{\sum_h^H w_h D_h(p_f)}{\sum_h^H D_h(p_f)} \qquad (10)$$

3.5. Equilibrium with a technology mix

With a technology mix the situation becomes more complex because of different costs and capacities of the technologies and adding the annual capital costs. This situation is demonstrated in Figure 17 where six different technologies are represented from low (hydro) to high (peak power) marginal cost technologies. Together their capacities form the long run capacity limit of the power markets (K_{tot}^{LR}). With low demand less capacity is needed as illustrated by demand D_j in the figure, when the capacities of midmerit and peak power are not needed to fulfil the demand. When the demand is very high, illustrated by D_k in the figure, all capacities are needed with RTP to balance supply and demand.

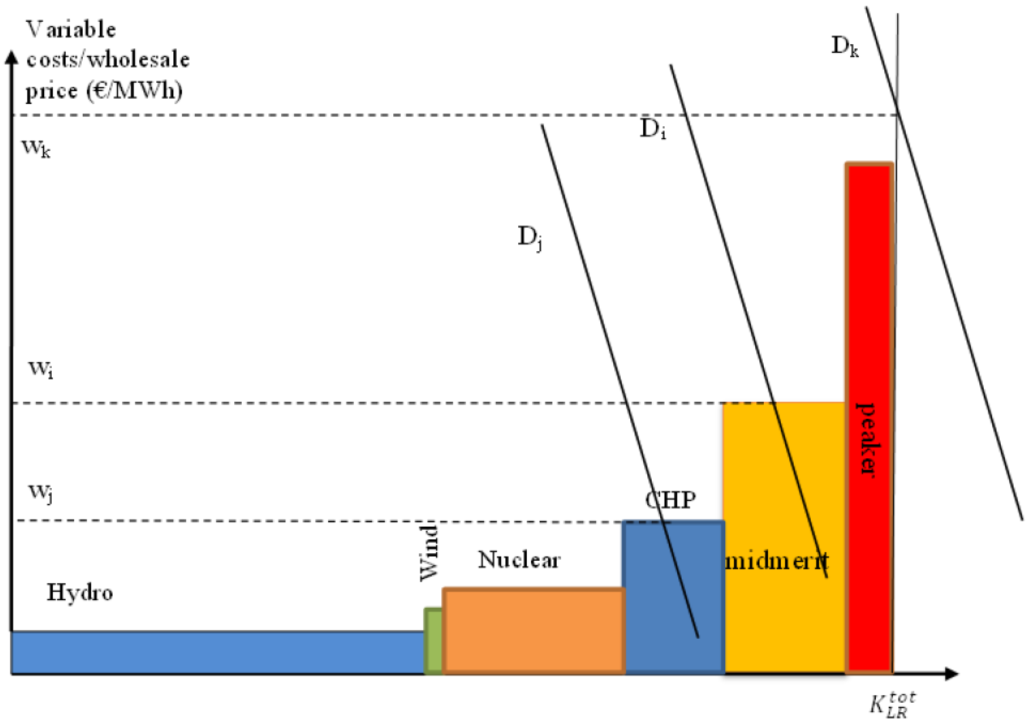


Figure 17 Long-run structure of the power markets. (Kopsakangas-Savolainen & Svento, 2013c, 146)

Once the demand for each hour and generation costs and capacity constraints are known, capacities for different generators can be calculated. Because of competition capacity is built to the point where zero profits are earned or the capacity constraint is reached (hydro, nuclear and wind technologies are capacity constrained). A Short-run technology mix is solved where producers sell the electricity to retail sector that sells it again to customers in real-time pricing and flat pricing. After this a flat price that drives the profits of the retail sector to zero is calculated. The new flat price is then used to solve the technology mix again and these two loops run as long as profits of both the retail and production sector go to zero and the long-time technology mix is solved. (Kopsakangas-Savolainen & Svento, 2013c, 145)

3.6. Running the model

The first step was to form the residual load duration curve. This was done by subtracting hourly wind production from hourly electricity consumption in 2014. Then assumptions about the share of customers in real-time pricing, price elasticity and flat price for anchor-points were made. Price data of different technologies and capacity constraints were also put in.

The model starts by guessing the amount of peak power capacity. If the profits are positive the capacity is increased and vice versa. Usually the last capacity before profits go below zero is the short run total capacity (K_{tot}^{SR}). The same is then done to midmerit capacity which substitutes peak power capacity until midmerit producers' profits go to zero. This capacity is K_{mid}. After midmerit capacity is solved it is substituted in the same way with base load power until its profits go to zero or all the capacity is used (the capacity of nuclear power). This capacity is K_b. Next the production of hydro power is taken into account at every hour of the year and this is K_{HP}. If the demand of an hour is less than the production of nuclear and hydro power combined hydropower is decreased to meet the demand and the excess hydropower is allocated to the later hours. (Kopsakangas-Savolainen & Svento, 2013c, 146-147)

After all these are known capacities of different technologies can be determined. Hydro power is K_{HP}, nuclear power is $K_b - K_{HP} = K_{NP}$, conventional thermal power = $K_{CT} = K_{mid} - K_{HP} - K_{NP}$ and peaker power = $K_{PP} = K_{tot}^{LR} - K_{CT} - K_{NP} - K_{HP}$. These are the short run capacities of different technologies. (Kopsakangas-Savolainen & Svento, 2013c, 146-147)

Next the profits of the retail sector are checked. Profits should go to zero because of competition. This is done by adjusting the flat rate price to force the profits of retailers to zero. After this adjustment generator capacities are solved again with the new flat rate price and the algorithm goes on until retail markets also go to zero profits. The model run is complete when both sectors receive zero profits. When this is achieved the model results in the long run competitive equilibrium of the power markets. The size and structure of the system depend on available technologies and their prices and capacities and the share of customers in RTP and customers' price elasticity, as well as the shape of the load duration curve. (Kopsakangas-Savolainen & Svento, 2013c, 147)

4. Data and Scenarios

To use the model information about production technology capacities and their generation and capital costs are needed as well as information about hourly consumption in the Nordic electricity markets.

4.1. Technology and Demand

Consumption data for year 2014 was taken from Nord Pool's website where hourly data for consumption of electricity in Nordic countries is available. Hourly data was organized in order of magnitude to form the load duration curve (Figure 14, 35). Load duration curve was used in the demand function to take into account demand differences between hours.

Capacities of wind, hydro and nuclear power were constrained in the simulations. Wind power was assumed to expand in the coming years and this was achieved in the modelling by multiplying the hourly wind power curve before subtracting it from the load duration curve. Wind power production (2014) was doubled in the simulations and the resulting amount was about 56,3 TWh/a. This was a conservative scenario compared for example to the IEA scenarios in page 19 (ca. 60 TWh in 2030 and 80 TWh/a in 2035 in the CNS scenario). The hourly wind production data was gathered from Nord Pool (Danish production), Finnish energy and Svenska kraftnät (Swedish production). The production of 2014 was available hourly for these countries but Norwegian wind production was not found. Thus the data from Finland, Sweden and Denmark was scaled based on the wind capacities of the countries in 2013 to take the Norwegian production into account. Hourly wind production data was organized alongside the hourly consumption data and subtracted from it in Excel to form the residual load duration curve.

The capacity of hydropower was taken from the CES-study (Nordic Council of Ministers, 2012, 181). In CES 49,3 GW for Nord Pool was used. In this thesis an assumption was made that due to renovations and new installations an additional 10 TWh/a is produced in the hypothetical year in 2030-2035. In CES 201,8 TWh/a is produced with 49,3 GW capacity so simply calculating 211,8 TWh/a could be produced with 51,7 GW capacity. In the study the annual hydro production amount was varied. I used the results of the CES study where inflow and hydro production scenarios with a 1961-1990 (reference period) and 2021-2050 (two future scenarios) are presented. Future climate scenarios resulted in ca. 10 % more hydro power production annually (see Figure 13, page 30) (Nordic Council of Ministers, 2012, 185).

The capacity of nuclear power was kept the same as in 2014 (9683,8 MW/h through the year, ENTSO-E, see Figure 3, page 11). It is interesting to see what happens to nuclear power in Nordic countries in the coming decades as reactors are possibly being phased out in Sweden and Finland and new reactors are being built and planned in Finland. It was also studied how changing the amount of nuclear power affects the results. World Nuclear Association (World Nuclear Association, 2016) has information about present reactors and ones being built/planned in Finland and Sweden. Before 2035 6 reactors (4 in Sweden and 2 in Finland) equivalent of 3772 MWe are expected to shut down and two new reactors (Finland) equivalent of 2920 MWe are expected to be built. The resulting capacity is 7% smaller than in 2014.

In the model two out of five technologies produce emissions to the atmosphere. Emissions were calculated with coefficients used in Motiva’s report (Motiva 2012, 6). For gas 198 $kgCO_2/MWh$ was used and for peat 381 $kgCO_2/MWh$ was used. Coefficients were originally from Statistics Finland (2012) and do not include emissions from fuel production, materials or transportation.

4.2. Costs

Investment and variable costs of producers were based on the calculations of Vakkilainen, Kivistö & Tarjanne (2012) concerning wind, nuclear, midmerit and peak power technologies. Hydro power costs were taken from Huuki, Kopsakangas-Savolainen & Svento (2014) and were based on estimates in the literature. Cost structures of these generators are quite different as wind and hydro generators have negligible variable costs (no fuel costs) and thermal generators have higher variable costs but in general lower investment costs. Nuclear generators have variable costs in between these two ends and high investment costs. According to Vakkilainen, Kivistö & Tarjanne (2012) nuclear power is capable of producing power with lowest costs of the generator types studied while wind power is noted to have the potential to become the most economical in the future (hydro power not taken into account). Besides different costs the ability to adjust output varies between technologies: in general thermal and hydro plants can adjust their production while nuclear plants' production is more constrained. Wind power production is depended on the wind conditions.

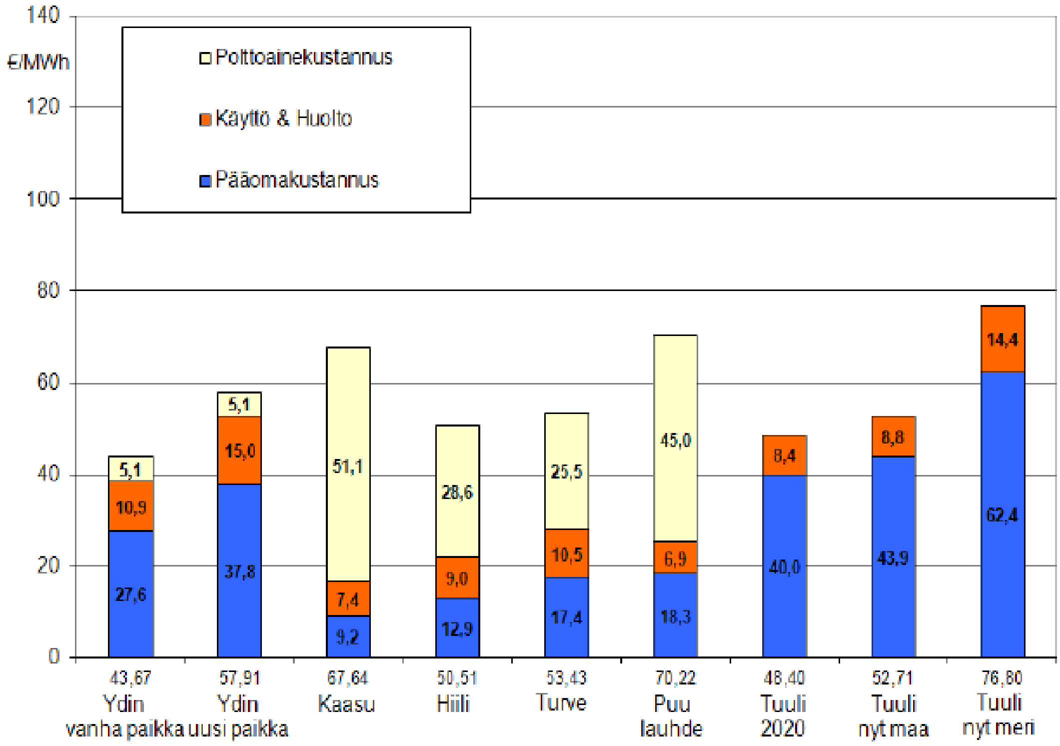


Figure 18 Power production costs (€/MWh) of different generators. Capital costs in blue, usage and repair in orange and fuel costs in white. From the left: New nuclear on an old spot, new nuclear on a new spot, gas, coal, peat, wood, wind 2020, wind on-shore, wind off-shore. Emission trading increases the costs of gas, coal and peat generators. (Vakkilainen; Kivistö; & Tarjanne 2012, 11)

When the investment cost and the economic lifetime of the power plant is known annual capital costs can be calculated. They were calculated using the standard annuity formula (11) with a 5% interest rate. Investment costs were needed annually because also the model simulates production over one year.

$$k = K_0 * \frac{r * (1 + r)^a}{(1 + r)^a - 1} \qquad (11)$$

k=annual investment cost, K_0=investment cost, r=interest rate, a=lifetime of the investment

To calculate the costs and emissions of midmerit and peak power technologies information of the generators behind these technologies was needed. A scenario was made that in a hypothetical year in 2030-2035 peak power is produced by gas and conventional midmerit power is produced by biomass (9/10) and peat (1/10). This is visible in the costs with different EUA prices as EUA affects peak power's generation costs much more than midmerit's costs.

Wind power participates in the model only as "negative load" in this thesis but their costs were calculated from Vakkilainen, Kivistö & Tarjanne (2012) out of interest. It is also an interesting question out of this thesis' scope how wind and hydropower interplay and how more hydro power potential might affect it.

Table 4 Cost data used in the modelling, based on Vakkilainen, Kivistö & Tarjanne (2012).

Generation type	**Investment cost/kW**	**Economic lifetime**	**Annual capital costs €/MW 5% interest rate**	**Variable costs €/MWh**	**Variable costs €/MWh, EUA price 6€/tCO_2**	**Variable costs €/MWh, EUA price 30€/tCO_2**	**Variable costs €/MWh, EUA price 60€/tCO_2**
Wind	1240	25	87,994	8,4	8,4	8,4	8,4
Hydro	2,000	75	102,651	4	4	4	4
Nuclear	3,788	40	220,751	16,08	16,08	16,08	16,08
Midmerit	2057	25	145,947	50,3	50,87	53,16	56,01
Peak	1032	25	73,222	58,48	60,52	68,67	78,85

4.3. Scenarios

Climate change impacts on hydro power production in the electricity markets were studied in different scenarios that were based on various assumptions about climate and energy policies. Different scenarios result from different climate & energy policies/projections and the studied impact results from climate change. Results of the abovementioned CES-study (Nordic Council of Ministers, 2012) were used and they represented climate conditions for an average year in 2020-2050. Therefore in the scenarios I focused on a hypothetical year in 2030-2035. In order to do this, assumptions were made regarding e.g. technology capacities, electricity demand and emission allowance prices.

The amount of wind power was expected to double in every scenario. The technologies used in midmerit and peak generators were modified to represent a hypothetical year in 2030-2035. Phasing out coal production in the Nordic countries was assumed and thus midmerit generators used wood biomass (9/10) and peat (1/10) for fuel and peak generators used gas in the simulations. One scenario (7) was also ran with the price data from Kopsakangas-Savolainen & Svento (2013a) where midmerit generators used coal and peat and peak generators gas and oil for fuel.

The amount of nuclear power was kept at the level of 2014 in most scenarios. Some scenarios (2&4) were also studied with lower nuclear capacity. Information about new nuclear plants (2 units in Finland) and old ones being phased out or decommissioned (6 units in Finland and Sweden) was obtained from World Nuclear Association (World Nuclear Association, 2016). The price of EUA was 6€ in most scenarios which was more or less the average price in the year 2014 (EEX, 2016). In scenarios 5-7 also other EUA prices were used.

The amount of hydropower was varied in different scenarios listed below. In the baseline hydro power produces 201,8 TWh/year. This amount is taken from the CES-study where it represents an average year in a 1961-1990 climate (Nordic Coucil of Ministers, 2012, 184). In the next step 10 TWh/year was added because of assumed new production and upgrades of the old hydro generators and the resulting amount was 211,8 TWh/a. This was a conservative scenario compared to the the CNS-scenario in Nordic Energy Technology Perspectives (OECD/IEA, 2013, 63) where the amount of hydropower is 241-246 TWh/a in Nordic countries in 2030-2035. The annual hydropower production of 211,8 TWh/a was then increased as a result of climate change. I used in percentage terms about the same increase as was studied in the CES-study (ca. 10 %) (Nordic Council of Minister, 2012, 184) This way the effects of climate change to hydropower potential are studied in a very general level as hydro power is not optimized and the increase is divided evenly throughout the year but I believe the issue can be examined this way on a general level.

In one of the scenarios (6) average hydro production was scaled to the load duration curve (in this scenario hydropower was thus utilized more in the more loaded hours). In this scenario it was tried to highlight the annual differences in climate change impacts to hydro power production as more increase takes place in winter/spring months than in summer in many climate studies, like in the CES climate scenario 'Hadam' (Nordic Council of Ministers, 2012, 185). This was achieved simply by multiplying the hours in the hydro profile every four weeks with an approximate taken by eyesight from the figure 13 in the page 30. 'Hadam' scenario is the red line in the figure 13.

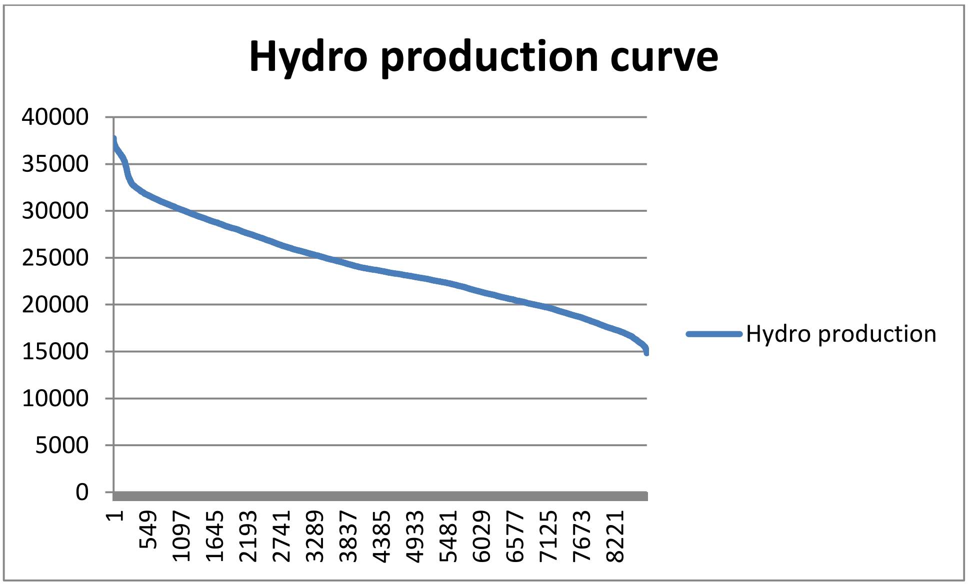


Figure 19 Hydro production scaled by hourly demand in the scenario 6. MWs in y axis and hours in x-axis.

Demand for electricity in the scenarios was represented by the year 2014. It was either the same or 6,7 % higher resulting from assumed increasing electricity demand. The growth in electricity demand was about the same as used in the CNS-scenario (OECD/IEA, 2013, 61) for years 2030-2035. The increase in demand was achieved simply by scaling the load duration curve hourly by +6,7 %.

Table 5 Scenarios where different amounts of hydro power were studied.

Scenario	Demand	Nuclear	EUA price
1.	2014 residual load curve	2014	6 €
2.	2014+6,5% residual load curve	2014	6 €
3.	2014 residual load curve	Some nuclear decommissioning	6 €
4.	2014+6,5% residual load curve	Some nuclear decommissioning	6 €
5.	2014+6,5% residual load curve	2014	30 & 60 €
6. Hydro scaled to load curve	2014+6,5% residual load curve	2014	30 €
7. Old prices	2014 residual load curve	2014	0 & 23 €

5. Results of model runs

Throughout the scenarios increasing the production of hydropower resulted in lower electricity prices. This was as expected as hydropower produces power with the lowest marginal costs in the model. Lower electricity prices resulted in lower profits for hydro and nuclear generators (midmerit and peak generators were not allowed to earn profits in the model) and lower billing costs for customers. Billing costs covered only the production of electricity and did not include e.g. transmission costs or taxes. Increasing hydropower also displaced thermal generators from the markets.

First I increased the production of hydropower by 10TWh/a (new generators and upgrades to old generators). In scenario 1 with the residual load duration curve of the year 2014 and with EUA price 6 € the mean price for electricity decreased 11 % (Table 6). Results show also lower billing costs for customers (-9 %), more electricity consumption (+1,3 %), lower hydro generator profits (-12,5 %), negative nuclear generator profits, smaller thermal capacity (and less use) and thus also lower emissions. After this the scenarios 2, 3 & 4 were ran and the results pointed in the same direction, although the impact in the markets was weaker in the other scenarios. I believe this is because the share of hydropower in markets is also smaller in these scenarios because of more demand and/or smaller nuclear capacity.

Table 6 Results from adding 10 TWh/a of hydro production to different scenarios.

Scenario	mean price, (€/MWh)	total billing costs, (million €)	total energy consumed, (TWh), wind excluded	hydro profits, (million €)	nuclear profits, (million €)
1. 2014 demand	**-11,1 %** (from 42,8 to 38,08)	**-9 %** (from 15360 to 13978)	**+1,3 %** (from 306 to 310)	**-12,5 %** (from 5881 to 5144)	**-309 %** (from 130 to -272)
2. 2014 demand +6,7%	**-7,3 %** (from 51,42 to 47,69)	**-5,4 %** (from 18993 to 17963)	**+0,6 %** (from 325 to 327)	**-4,9 %** (from 7511 to 7142)	**-36,7 %** (from 860 to 544)
3. 2014 demand, lower nuclear	**-9,4 %** (from 45,23 to 40,96)	**-7,5 %** (from 16035 to 14832)	**+1 %** (from 305 to 308)	**-9 %** (from 6343 to 5769)	**-108 %** (from 312 to -25)
4. 2014 demand +6,7%, lower nuclear	**-6,8 %** (from 53,52 to 49,88)	**-5 %** (from 19553 18574)	**+0,7 %** (from 323,2 to 325,5)	**-4,2 %** (from 7897 to 7568)	**-29,7 %** (from 966 to 679)

Table 7 Results from adding 10 TWh/a of hydro production to different scenarios.

Scenario	midmerit generator capacity, (MW)	peak generator capacity, (MW)	hours at peak generator, (h)	emissions per consumption, (tCO_2/MWh)
1. 2014 demand	-	**-13,4 %** (from 15 792 to 13 668)	**-27,5 %** (from 3350 to 2430)	**-33,8 %** (from 0,013 to 0,0086)
2. 2014 demand +6,7%	-	**-7,5 %** (from 20 514 to 18 973)	**-13,7 %** (from 5020 to 4331)	**-21,7 %** (from 0,023 to 0,018)
3. 2014 demand, lower nuclear	-	**-11,5 %** (from 16 919 to 14 972)	**-22,1 %** (from 3842 to 2992)	**-31,3 %** (from 0,016 to 0,011)
4. 2014 demand +6,7%, lower nuclear	-	**-6,8 %** (from 21 359 to 19 914)	**-13,3 %** (from 5452 to 4728)	**-19,2 %** (from 0,026 to 0,021)

Hypothetically this (201,8 + 10 TWh/a) could be the amount of hydropower produced in the Nordic countries in an average year in 2030-2035 without climate change. To this amount of hydro power the climate change impacts (+10%) were studied.

Results of adding the climate change impact point at the same direction as above but the changes are bigger (Table 8) and again biggest in the scenario 1. Interestingly increasing the capacity of hydropower relatively little (10%) affected the results strongly. Mean price of electricity decreased between 16,2 – 26 % in scenarios 1-4 when increases to hydro production were added. This resulted again in more electricity consumption (1,8 – 3,2 %) and smaller billing costs (-12,7 - -23,6 %). The profits of the hydro and nuclear generators decreased a lot as the price of electricity decreased. Surprisingly the climate change impact was negative also to hydro producers although their production and market share increased. Nuclear generators made positive profits only in scenario 4 and losses in scenarios 1-3. Peak generator capacity decreased also between 18,7 and 58,5 % as did its usage (33,2 - 74,2 % less hours when peak power was utilized). The studied electricity demand increase had a bigger impact on the results than the studied decrease in nuclear power production.

Table 8 **Results from adding 10 % of hydro production as a result of climate change in different scenarios.**

Scenario	**mean price, (€/MWh)**	**total billing costs, (million €)**	**total energy consumed, (TWh), wind excluded**	**hydro profits, (million €)**	**nuclear profits, (million €)**
1. 2014 demand	**-26 %** (from 38,08 to 28,19)	**-23,6 %** (from 13 978 to 10 680)	**+3,2 %** (from 310,0 to 319,8)	**-42,7 %** (from 5144 to 2945)	**-310 %** (from -271 to -1110)
2. 2014 demand +6,7%	**-17,8 %** (from 47,69 to 39,20)	**-14,3 %** (from 17 963 to 15 395)	**+2,0 %** (from 327,0 to 333,5)	**-17,2 %** (from 7142 to 5911)	**-133 %** (from 544 to -177)
3. 2014 demand, lower nuclear	**-24,2 %** (from 40,96 to 31,05)	**-21,0 %** (from 14 832 to 11 710)	**+2,8 %** (from 307,7 to 316,4)	**-33,9 %** (from 5769 to 3813)	**-3130%** (from -25 to -807)
4. 2014 demand +6,7%, lower nuclear	**-16,2 %** (from 49,88 to 41,81)	**-12,7 %** (from 18 574 to 16 220)	**+1,8 %** (from 325,5 to 331,4)	**-13,8 %** (from 7568 to 6523)	**-93,7 %** (from 679 to 43)

Table 9 Results from adding 10 % of hydro production as a result of climate change in different scenarios.

Scenario	midmerit generator capacity, (MW)	peak generator capacity, (MW)	hours at peak generator, (h)	emissions per consumption, (tCO_2/MWh)
1. 2014 demand	-	**-58,5 %** (from 13 668 to 5671)	**-74,2 %** (from 2430 to 628)	**-34,6 %** (from 0,013 to 0,0085)
2. 2014 demand +6,7%	-	**-21,3 %** (from 18 973 to 14 930)	**-39,2 %** (from 4331 to 2635)	**-48,3 %** (from 0,018 to 0,0093)
3. 2014 demand, lower nuclear	-	**-41 %** (from 14 972 to 8764)	**-61,8 %** (from 2992 to 1144)	**-73,6 %** (from 0,011 to 0,0029)
4. 2014 demand +6,7%, lower nuclear	-	**-18,7 %** (from 19 914 to 16 181)	**-33,2 %** (from 4728 to 3160)	**-42,9 %** (from 0,021 to 0,012)

Increasing the ETS price to 30 and 60 €/tCO_2 (scenario 5) led to higher electricity prices, less energy consumption, smaller peak capacity and smaller emissions. With higher ETS price also the midmerit generators started to produce power. This happened because midmerit technology had smaller emissions (9/10 wood biomass and 1/10 peat for fuel) than peak technology (gas) in the simulations. The effect was stronger with the ETS price really high (60 €). However, midmerit technology vanished from the technology mix also in these scenarios when the impact of climate change to hydropower production was taken into account. In these scenarios mean price for electricity fell by 17 – 18,9 % after the climate change impact. Nuclear profits turned negative with the emission price at 30 € but stayed positive with the emission price at 60 € (still fell by 85,9 %).

In scenario 6 hydropower was not modelled as baseload like in other scenarios but as described in Figure 19. In this scenario the use of nuclear power was also not constrained. Impacts of climate change were studied in two ways: first by increasing the production of every hour as much and secondly weighing different hours of the year more than others like described also in the page 49. This was because the increase in hydropower production because of climate change could concentrate more on winter/spring (Nordic Council of Ministers, 2012, 141). In these scenarios the price of electricity did not decrease as much as nuclear capacity was less used when hydropower production was increased. Nevertheless, in these scenarios price decreased more and less nuclear power was used when the climate change impact was more concentrated on the winter/spring hours. Thus it might be that if more inflow was concentrated on winter/spring months profitability of nuclear plants and the mean price decreases more compared to the situation where the increase in inflow is evenly distributed through the year. On the other hand more peak generators were used when the increased hydro production was more concentrated on winter/spring months. Because of less nuclear power and more peak power emissions are higher in this scenario compared to when climate change impacts spread evenly throughout the year. Emissions fell nevertheless compared to the no climate change situation.

In the last scenario price data was taken from Kopsakangas-Savolainen & Svento (2013a, 21) where midmerit represented coal (ca. 65%) and peat (ca. 35%) fired production and peak generators represented oil fired power plants, older power plants and gas turbines. In this scenario results were quite as in scenarios 1-5: price of electricity decreased (mean price –19,5 % to –26,6 %), midmerit and peak capacities decreased, energy consumption increased and hydro and nuclear profits decreased (nuclear profits turned negative). In this scenario however increasing the price of ETS had different consequences on the capacities of midmerit and peak generators as in this scenario midmerit (coal, peat) produced more emissions than peak power (gas, oil).

According to the results increase in hydropower production decreases prices and thus also rents and profits of nuclear and hydro generators. In this setting profits of nuclear generators turned negative in most scenarios. Hydropower also displaced thermal producers from the markets. The decreased price resulted in more electricity consumption and smaller energy bill for customers. Also the emissions fell because of less thermal power production.

6. Discussion

6.1. The context of climate change and electricity production and consumption

Besides mitigating climate change the electricity markets need to adapt to it too and impacts to hydropower production and the indirect impacts of climate change are one dimension of the issue. Adapting to the indirect impacts of climate change in Finland might be in economic point of view as important as adapting to the direct impacts of climate change (Bosello, Orecchia & Standardi, 2015). From the electricity markets point of view it might be significant to Finland how the hydropower potential changes in Sweden and Norway in addition to changes in Finland. Wet years of 2014 and 2015 have contributed to low electricity prices in Nordic electricity markets and might it be that these wet years became the norm in the future as “there is little doubt that the Nordic and Baltic hydropower systems will be affected strongly by a changing climate” (Nordic Council of Ministers, 2012, 141). Although the uncertainties are large studies generally point to more hydropower production and changing annual inflows of water to reservoirs: more increase in the winter/spring than in summer when the inflow can even be decreased (Table 3, 31).

Electricity markets are facing throughout changes as climate and energy policies aim to change the ways electricity is produced, distributed and consumed. Climate change mitigation efforts have and will increase the amount of renewable production in Nordic countries as well as in the continental Europe. Subsidized wind power with negligible variable costs has posed new challenges to the Nordic electricity markets where electricity is traded according to the marginal costs. Wind power has decreased the price of electricity in general and thus the profitability of other technologies (Liski & Vehviläinen, 2015). Low electricity price is causing problems to many generators and old generators have been shut down in Finland due to bad profitability (Aamulehti, 2015) and with the current electricity prices it is not economical to invest in new electricity production in Nordic countries (Fortum, 2015, 16). Climate change impacts to hydropower could possibly contribute to these issues and make for example new nuclear power plant investments less profitable and there is already a discussion going on are they profitable to begin with (see e.g. HS, 2014). So this is an issue that might be good to recognize when investments are made and security of supply and balancing power are ensured. Impacts of climate change might relate to the discussion about security of supply and capacity markets also from the point of view that volatility of Nordic conditions could increase because of climate change – wet and warm winters decrease heating energy demand and increase hydro production, but cold and dry years are probably not impossible also in the future.

The Nordic electricity markets are in a privileged position to increase renewable production because of the current capacity of hydropower. Hydropower is partly capable of storing water in reservoirs and adjusting its production according to the situation in the markets (e.g. Denmark has lots of wind production and handles it partly with help of Norwegian hydropower). However, there is a discussion in Finland is there enough balancing power when new wind generators are built (YLE, 2012). Question is topical also in continental Europe and UK which are looking towards Nordic hydro reservoirs and new interconnectors are being built (DW, 2015). Thus the role and demand of Nordic hydropower is potentially changing in the future which might affect also this thesis' results crucially.

On the other hand low electricity prices are good news for electricity customers in Finland. Low prices are also good from the point of view that in Finland in 2014 roughly a fourth of the consumption of electricity was imports and most of the imports came from Sweden (Finnish Energy, 2016b). So the climate change's potential to increase hydropower production in the Nordic countries might be a positive thing to recognize as new interconnector to Sweden is being discussed (HS, 2015b). Esa Härmälä, director of energy affairs in ministry of employment and the economy in Finland, noted in Pohjolan Voima's (a Finnish energy company) discussion about sufficiency of Finnish balancing power that "if we can entrust in the Swedish and Norwegian hydropower as balancing power, we do not really have a problem" (Pohjolan Voima, 2012, 10, in Finnish).

The future will tell how the Nordic electricity markets change as the Nordic markets become more integrated with the rest of Europe. As new interconnectors start working and the interplay with renewables and the Nordic hydropower strengthens hydropower's role in the system might change. In this turmoil it might be valuable in Finland to be aware of climate change's potential impacts to hydrology in Sweden and Norway. Uncertainties of these impacts are of course essential and necessary to keep in mind.

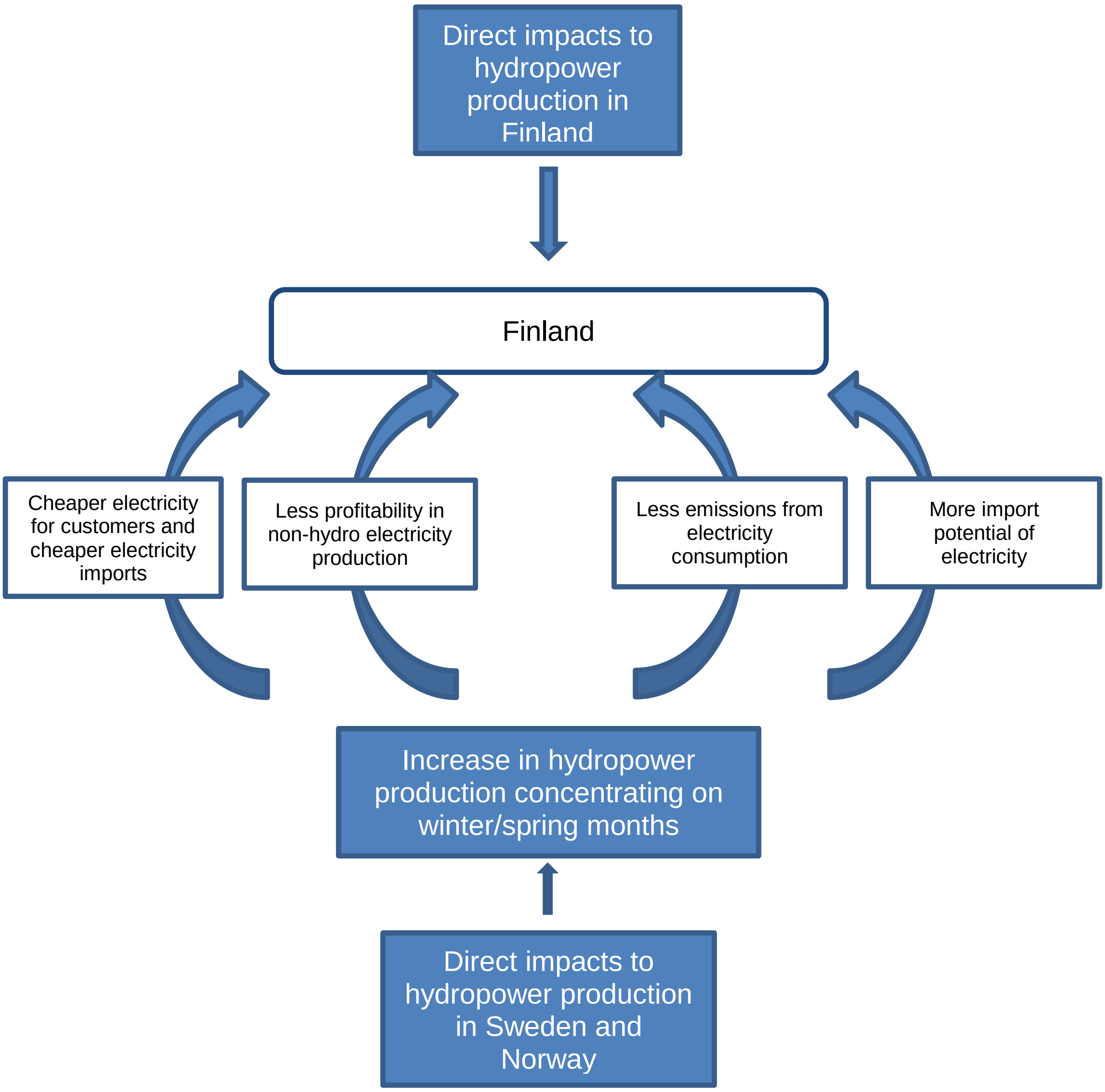


Figure 20 Potential indirect impacts of climate change to Finland due to more hydropower production in the electricity markets.

6.2. Results and discussion in the light of other studies

The results go well together with the CES-study (Nordic Council of Ministers, 2012, 182). In this study also the price of electricity and thermal production decreased (mostly in Finland and Denmark). Hydro-dominated countries Norway and Sweden increased exports while Finland and Denmark reduced their net exports (Finnish imports increase in both climate scenarios). The study used the EMPS-model where transmission capacities inside Nordic markets and to continental Europe were also modelled. The study was done with a 2020 Nordic energy system that was studied with two future climate change scenarios (2021-2050 climate) that were compared to the baseline (1961-1990) climate scenario.

Merging of the Nordic and other power markets might also change the markets so that the impacts of climate change to the electricity price and the indirect impacts might not be as strong as they would to the present markets. The CES-study was done with an energy market simulation based on a scenario for year 2020 where new interconnectors from Nordic countries to Continental Europe were included (Nordic Council of Ministers, 2012, 181) and the abovementioned impacts of climate change took place in this setting.

Climate change can affect Nordic electricity markets also in other ways than by changing hydrological conditions. Warmer winters mean less demand for heating energy and might thus again contribute to increasing exports from Sweden and Norway, which was not included in this thesis but was studied for example in the CES-study. In the CES study the electricity demand is 7,6 - 11 TWh/a (ca. 2 %) lower in the climate change scenarios compared to the baseline climate scenario. (Nordic Council of Ministers, 2012, 186) Also in Seljom et. al. (2011) warmer winters contributed to increasing power exports from Norway.

6.3. Evaluation of the model used

It is better to view the results in relative terms rather than to look at the exact figures. There are many aspects that are not in the scope of this study. The model is not specifically made for hydro power modelling which is one weakness in the study. The model does not optimize hydro production but different hydro production profiles can be exogenously inserted in to the model (Kopsakangas-Savolainen & Svento 2013a). In this study hydropower was mostly modelled producing power evenly through the year. In reality the structure of different technologies is also more complex than described in this thesis (heat markets are not included so CHP electricity production is also not included in the study). Due to the costs that I used in the study midmerit generators do not even produce electricity in the main (1-4) scenarios as there is not enough hours for them to cover annual costs (in test simulations with less baseload capacity midmerit generators also played a role). Thus, in practice most simulations were done with electricity-only markets that consisted of hydro, wind, nuclear and peak (gas) generators. The basic structure of the markets could be nevertheless simulated and the effect of increasing the least cost production technology studied on a general level.

Also the model does not take into account the transmission constraints. There are limits to the amount of power that can be moved with the current interconnectors. When the transmission capacity between two areas is congested they divide into different price areas so the Nordic electricity markets cannot always allocate supply and demand most efficiently. This creates limits for example for the distribution of hydropower from Sweden and Norway to Finland and is also essential regarding the indirect impacts of climate change. Obviously fully integrated (no bottlenecks) and efficient markets would make a stronger pathway for indirect impacts. But even though the transmission capacity between Finland and Sweden is quite congested prices between the areas are the same most of the time (figure 21). Finland had a common price with Sweden 78% and with Norway and Denmark 92% of the time in 2013 (NordReg, 2014, 22). In the model Nordic markets are treated as one price area without transmission capacity constraints.

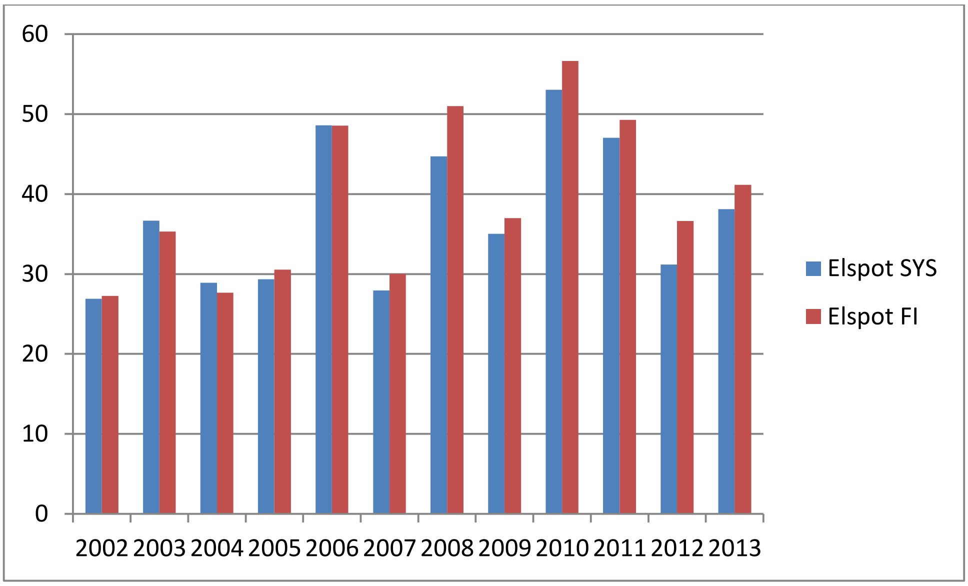


Figure 21 Elspot prices for electricity differ between areas because of bottlenecks but the trends are similar. Yearly mean system and Finnish area price for electricity in 2002-2013. (Source: Statistics of Finland)

Also I studied the change in hydropower potential in a simple way (one year, climate change or no climate change) and a more realistic method would possibly be to simulate the markets in a longer timescale than one year. This way differences between dry and wet years could be included in the study which would probably impact the capacities and profits of different technologies. As more production is based on renewable resources in the future it might be also interesting to study differences of dry and unwindy and wet and windy years and thus take also into account yearly differences in wind production.

7. Conclusions

At the moment Finland is very depended on electricity imports and changes in Nordic electricity markets have reflections in Finland too. Among all the changes in Nordic electricity markets following from climate change mitigation also climate change impacts can reshape production and consumption of electricity although the uncertainties are large. Indirect impacts are a useful concept in this sector as Finland is part of international well-functioning electricity markets where weather and climate affect the demand and production of electricity. Hydropower is an important technology in the markets and probably even more in the future when more intermittent production enters the grid. Hydro production in Nordic countries is going to be affected by climate change and most of it (94 % of total production in 2014, ENTSO-E) is situated outside Finland. Thus impacts to Norwegian and Swedish hydro power should be recognized also in Finland. From the Finnish point of view this might mean (compared to no climate change situation) e.g.: lower electricity prices, less profitability in non-hydro production and more electricity import possibilities. The impacts can be divided by their nature to economical (impacts on prices and markets) and physical (more potential of renewable power imports and less emissions) (Figure 20, 57). The study in this thesis was simplified and a more profound study about the subject could possibly give interesting results. Also the indirect impacts of climate change might be overrun by other changes in the electricity markets. Other studies could be made with e.g. more realistic hydro power modelling combined with climate scenarios or an economic regression model of the Nordic conditions and electricity markets where also impacts to electricity demand could be studied. In any ways, large uncertainties are present with the climate change and the future of electricity markets.

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Data sources

ENTSO-E – production of electricity by fuel source in Finland, Denmark, Sweden, Norway, 2014

https://www.entsoe.eu/data/data-portal/Pages/default.aspx

NordPoolSpot – hourly consumption of electricity in 2014, hourly wind power production in Denmark 2014, Nordic hydro power reservoirs by week in 2013 and 2014, Electricity consumption in the Nordic countries daily in 2013-2014, price of electricity yearly in 2002-2013

http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/?view=table

Finnish Energy – hourly wind production in Finland in 2014

http://energia.fi/tilastot-ja-julkaisut/sahkotilastot/sahkon-tuntidata

Svenska kraftnät – hourly wind production in Sweden in 2014

http://www.svk.se/aktorsportalen/elmarknad/statistik/?_t_id=1B2M2Y8AsgTpgAmY7PhCfg%3d%3d&_t_q=statistik&_t_tags=language%3asv&_t_ip=192.121.1.150&_t_hit.id=SVK_WebUI_Models_Pages_ArticlePage/_3936ae12-4e45-4dd5-a1a0-7ba2b30506e0_sv&_t_hit.pos=1

ANNEX 1 – all the results of the model runs

Scenario 1:

Scenario 2014 demand (ETS 6€)	flat rate (€/MWh)	mean price (€/ MWh)	min price (€/ MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/ MWh)	total energy consumed (million MWh)
Baseline	52.34	42.80	16.08	7096.14	0	15792	3.905506e+00	1.274791e-02	3.063644e+02
Baseline + 10TWh/a	47.33	38.08	16.08	7161.50	0	13668	2.637543e+00	8.509237e-03	3.099623e+02
Baseline + 10 TWh/a + 10% CC	35.52	28.19	16.08	7356.49	0	5671	3.664135e-01	1.146202e-03	3.196761e+02

Scenario 2014 demand (ETS 6€)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP customers (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	5880.744430	129.063904	6010.502799	8760	8760	0	3350	127	4845.031229	10514.899401	15359.930630
Baseline + 10TWh/a	5143.974152	-271.572208	4872.731701	8760	8760	0	2430	125	4373.760768	9604.563442	13978.324211
Baseline + 10 TWh/a + 10% CC	2945.008049	-1110.139227	1835.101416	8760	8760	0	628	117	3261.709694	7417.890821	10679.600515

Scenario 2:

Scenario 2014 demand + 6,7 % (ETS 6€)	flat rate (€/MWh)	mean price (€/ MWh)	min price (€/ MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/ MWh)	total energy consumed (million MWh)
Baseline	60.50	51.42	16.08	6691.49	0	20514	7.502618e+00	2.311827e-02	3.245319e+02
Baseline +10TWh/a	57.00	47.69	16.08	6729.82	0	18973	6.012427e+00	1.838621e-02	3.270074e+02
Baseline + 10 TWh/a +10% CC	48.33	39.20	16.08	6843.26	0	14930	3.106420e+00	9.314231e-03	3.335133e+02
Baseline + 10 TWh/a +15% CC	43.20	34.57	16.08	6921.42	0	12141	1.852561e+00	5.484635e-03	3.377729e+02
Baseline + 10 TWh/a +20% CC	37.69	30.00	16.08	7013.78	0	8060	7.302959e-01	2.131023e-03	3.426974e+02

Scenario 2014 demand + 6,7 % (ETS 6€)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	7510.611220	859.911036	8371.269802	8760	8760	0	5020	138	6069.717506	12923.463293	18993.180799
Baseline + 10TWh/a	7141.721676	543.810365	7685.876580	8760	8760	0	4331	138	5714.410950	12248.599840	17963.010791
Baseline + 10 TWh/a +10% CC	5911.335329	-176.840302	5735.062413	8760	8760	0	2635	135	4836.351862	10558.304724	15394.656587
Baseline + 10 TWh/a +15% CC	4975.004210	-569.320982	4406.321287	8760	8760	0	1808	135	4313.374942	9544.088297	13857.463239
Baseline + 10 TWh/a +20% CC	3821.595244	-956.691509	2865.167446	8760	8760	0	948	132	3753.682473	8441.169093	12194.851566

Scenario 3:

Scenario 2014 demand (ETS 6€, lower nuclear)	flat rate (€/MWh)	mean price (€/MWh)	min price (€/MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/MWh)	total energy consumed (million MWh)
Baseline	54.80	45.23	16.08	7066.02	0	16919	4.745642e+00	1.557643e-02	3.046682e+02
Baseline + 10TWh/a	50.42	40.96	16.08	7121.53	0	14972	3.367373e+00	1.094338e-02	3.077086e+02
Baseline + 10 TWh/a + 10% CC	39.19	31.05	16.08	7291.48	0	8764	9.043722e-01	2.857844e-03	3.164527e+02

Scenario 2014 demand (ETS 6€, lower nuclear)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	6342.925335	311.720688	6655.484057	8760	8760	0	3842	130	5076.273782	10958.655593	16034.929375
Baseline + 10TWh/a	5769.053553	-24.980957	5744.800383	8760	8760	2992	2992	126	4665.147419	10167.105563	14832.252982
Baseline + 10 TWh/a + 10% CC	3812.853772	-806.835495	3006.505372	8760	8760	1144	1144	120	3606.711137	8104.244085	11710.955222

Scenario 4:

Scenario 2014 demand +6,7% (ETS 6€, lower nuclear)	flat rate (€/MWh)	mean price (€/ MWh)	min price (€/ MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/ MWh)	total energy consumed (million MWh)
Baseline	62.41	53.52	16.08	6669.80	0	21359	8.421122e+00	2.605292e-02	3.232313e+02
Baseline + 10TWh/a	59.07	49.88	16.08	6705.36	0	19914	6.894388e+00	2.117948e-02	3.255221e+02
Baseline + 10 TWh/a + 10% CC	51.11	41.81	16.08	6805.23	0	16181	3.855692e+00	1.163604e-02	3.313578e+02

Scenario 2014 demand +6,7 % (ETS 6€, lower nuclear)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	7896.862317	965.750064	8863.167948	8760	8760	0	5452	138	6262.938606	13290.087515	19553.026120
Baseline + 10TWh/a	7567.622009	678.558600	8246.433039	8760	8760	0	4728	138	5925.403615	12648.218230	18573.621845
Baseline + 10 TWh/a + 10% CC	6522.954543	41.727410	6565.290462	8760	8760	3160	3160	136	5117.085113	11103.358678	16220.443791

Scenario 5 (ETS 30€):

Scenario 2014 demand +6,7 % (ETS 30€)	flat rate (€/MWh)	mean price (€/ MWh)	min price (€/ MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis- sions per consumption (tCO_2/ MWh)	total energy consumed (million MWh)
Baseline	64.84	55.01	16.08	6742.10	500	19646	6.703184e+00	2.078761e-02	3.224606e+02
Baseline + 10TWh/a	61.07	51.03	16.08	6786.27	0	18569	5.612353e+00	1.726953e-02	3.249858e+02
Baseline + 10 TWh/a + 10% CC	50.68	40.94	16.08	6907.76	0	14545	2.852689e+00	8.586478e-03	3.322304e+02

Scenario 2014 demand +6,7 % (ETS 30€)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	8299.412582	1164.825059	9464.426132	8760	8760	4987	4635	132	6476.335843	13754.910915	20231.246758
Baseline + 10TWh/a	7932.987296	827.277625	8761.305709	8760	8760	0	4148	130	6094.851193	13032.994273	19127.845466
Baseline + 10 TWh/a + 10% CC	6405.807572	-28.627178	6377.407001	8760	8760	0	2470	125	5050.585475	11019.249639	16069.835114

Scenario 5 (ETS 60€):

Scenario 2014 demand +6,7 % (ETS 60€)	flat rate (€/MWh)	mean price (€/ MWh)	min price (€/ MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/ MWh)	total energy consumed (million MWh)
Baseline	67.08	56.39	16.08	6835.69	4006	15946	4.301888e+00	1.337825e-02	3.215584e+02
Baseline + 10TWh/a	63.81	52.94	16.08	6868.57	2282	16019	4.016948e+00	1.240568e-02	3.237991e+02
Baseline + 10 TWh/a + 10% CC	53.35	42.92	16.08	6991.50	0	14117	2.590289e+00	7.827898e-03	3.309048e+02

Scenario 2014 demand +6,7 % (ETS 6€)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	8605.762636	1281.951452	9887.979599	8760	8760	4911	3099	123	6676.178444	14181.847956	20858.026400
Baseline + 10TWh/a	8389.655263	989.097214	9378.962789	8760	8760	4185	3100	122	6342.311629	13558.103553	19900.415182
Baseline + 10 TWh/a + 10% CC	6971.828432	139.073292	7111.493528	8760	8760	2306	2306	122	5292.196609	11540.378628	16832.575237

Scenario 6:

Scenario 2014 demand +6,7 % (ETS 30€), curves	flat rate (€/MWh)	mean price (€/ MWh)	min price (€/ MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/ MWh)	total energy consumed (million MWh)
Baseline 201.8	64.85	54.59	4.00	8744.54	2254	28037	1.006851e+01	3.111735e-02	3.235659e+02
Baseline + 10TWh/a	63.46	53.02	4.00	8864.88	1173	28490	1.001239e+01	3.082545e-02	3.248092e+02
Baseline + 10 TWh/a + 10% CC	60.05	49.29	4.00	9125.08	0	28361	9.142270e+00	2.789120e-02	3.277832e+02
Baseline + 10 TWh/a + 10% CC2	59.67	48.99	4.00	10098.18	0	29193	9.359398e+00	2.852347e-02	3.281298e+02

Scenario 2014 demand +6,7 % (ETS 30€), curves	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	4951.6815871241.087456	1241.087456	6193.230493	8760	7710	5325	4651	97	6437.640281	13756.820126	20194.460408
Baseline + 10TWh/a	4838.068723	1135.350375	5974.220881	8760	7456	5024	4651	96	6291.589646	13491.155171	19782.744817
Baseline + 10TWh/a+10 % CC	4420.439514	879.719744	5300.561548	8760	6930	4356	4356	92	5935.859743	12836.918591	18772.778333
Baseline + 10 TWh/a+10%CC2	4210.002781	860.675817	5071.000178	8760	6862	4314	4314	89	5892.315095	12763.785893	18656.100988

Scenario 7 (ETS 0€):

Scenario 2014 demand (old prices, ETS 0€)	flat rate (€/MWh)	mean price (€/ MWh)	min price (€/ MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/ MWh)	total energy consumed (million MWh)
Baseline	37.76	32.13	15	3923.67	3815	14751	n/a	n/a	3.146892e+02
Baseline + 10TWh/a	36.11	30.47	15	3940.81	1653	14809	n/a	n/a	3.164265e+02
Baseline + 10 TWh/a + 10% CC	29.42	24.53	15	4011.52	0	10188	n/a	n/a	3.235368e+02

Scenario 2014 demand (old prices, ETS 0€)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	4326.121680	303.296526	4629.538593	8760	8760	4256	2568	102	3702.143612	7837.608438	11539.752050
Baseline + 10TWh/a	4222.973851	163.125267	4386.452746	8760	8760	3413	2568	102	3539.554519	7528.691735	11068.246254
Baseline + 10 TWh/a + 10% CC	3126.059242	-340.85 6703	2785.285370	8760	8760	0	1309	100	2893.002705	6260.848244	9153.850950

Scenario 7 (ETS 23€):

Scenario 2014 demand (old prices, ETS 23€)	flat rate (€/MWh)	mean price (€/MWh)	min price (€/MWh)	peak price (€/MWh)	midmerit capacity (MW)	peak capacity (MW)	total emissions (million tCO_2)	emis-sions per consumption (tCO_2/MWh)	total energy consumed (million MWh)
Baseline	46.54	39.48	15	3988.16	0	17310	n/a	n/a	3.088054e+02
Baseline + 10TWh/a	42.05	35.16	15	4022.87	0	15382	n/a	n/a	3.123283e+02
Baseline + 10 TWh/a + 10% CC	31.30	25.81	15	4124.26	0	9250	n/a	n/a	3.220469e+02

Scenario 2014 demand (old prices, ETS 23€)	hydro profits (million €)	nuclear profits (million €)	total profits (million €)	hours at hydro (h)	hours at nuclear (h)	hours at mid-merit (h)	hours at peak (h)	hours at full capacity (h)	billing costs for RTP (million €)	billing costs for flat rate customers (million €)	total billing costs (million €)
Baseline	6025.004048	927.423564	6952.561586	8760	8760	0	3626	87	4489.084426	9460.160761	13949.245187
Baseline + 10TWh/a	5410.967657	561.150032	5972.287603	8760	8760	0	2754	85	4066.124704	8634.638812	12700.763516
Baseline + 10 TWh/a + 10% CC	3534.859442	-232.20 4601	3302.758974	8760	8760	0	1047	83	3052.872081	6619.797116	9672.669197